Washington Regulatory Assessment

Performance Based Regulation Docket U-210590

POLICY STAFF ANALYSIS AND STRAW PROPOSAL

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About the Utilities and Transportation Commission
The Washington Utilities and Transportation Commission provides regulated utility companies with information, services, and resources to help ensure they comply with state and federal laws and regulations. The Commission regulates the rates and services of investor-owned energy utilities, water utilities, telecommunications companies, solid waste collection companies, household-goods movers, passenger transportation companies, commercial ferries, pipeline companies, marine pilotage, and a low-level radioactive waste repository.

Our mission is to protect the people of Washington by ensuring investor-owned utility and transportation services are safe, equitable, available, reliable and fairly priced.

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Executive Summary

Legislative Requirement

Beginning January 1, 2022, Revised Code of Washington (RCW) 80.28.425 (MYRP Statute) requires electric and natural gas companies regulated by the Washington Utilities and Transportation Commission (Commission) to include in each general rate case filing a multiyear rate plan (MYRP). The statute further requires the Commission to determine a set of performance measures to assess a utility operating under a MYRP.

To that end, the Legislature directed the Commission, in Section 1 of Engrossed Substitute Senate Bill 5295 (ESSB 5295),[1] to conduct a proceeding to develop a **policy statement** addressing alternatives to traditional cost of service rate making, including performance-based measures or goals, targets, performance incentives, and penalty mechanisms. The Legislature further directed the Commission to consider a number of factors as part of such a proceeding, including, but not limited to, lowest reasonable cost planning, affordability, increases in energy burden, cost of service, customer satisfaction and engagement, service reliability, clean energy or renewable procurement, conservation acquisition, demand side management expansion, rate stability, timely execution of competitive procurement practices, attainment of state energy and emissions reduction policies, rapid integration of renewable energy resources, and fair compensation of utility employees.

Purpose of Policy Paper

The purpose of this paper is to assess Washington's current regulatory environment, mechanisms, and incentives to understand how all our tools interact to help balance utility risk and financial health with customer affordability and benefits.

The outcomes of this paper are intended to provide:

- a common understanding of the current regulatory environment (are utility incentives and customer benefits balanced);
- a tracking system for filings with rate impacts for the benefit of the Commission and the public; and
- recommendations for adjustments to existing regulatory mechanisms.

[1] Laws of 2021, ch. 188. Section 1 of the bill was not codified in Chapter 80.28 RCW.

This paper serves as a straw proposal for the recommendations resulting from the Policy Staff's regulatory assessment. The Commissioners have not participated in the research, recommendations, or findings contained in this paper. A formal Notice of Opportunity to Comment is provided in conjunction with the release of this paper.

Policy Staff have done their best to validate information and data to the best of their ability, given the compressed schedule for this research. Any inaccuracies may be addressed as provided for in the concurrently issued Notice of Opportunity to comment. As such, the information contained in this report is considered a straw proposal and should not be cited as formal Commission findings.

What is Alternative Regulation?

There is no standardized definition of alternative regulation. Rather, it is a broad term for any deviation from **traditional rate regulation**, also known as cost-of-service regulation. Performance-based regulation (PBR) is a framework that ties a company's revenues to specific, measurable outcomes rather than solely determining revenues based on utility costs.[2]

PBR is a common alternative regulation framework that provides regulators with multiple tools including multiyear rate plans (MYRPs), performance incentive mechanisms (PIMs), revenue decoupling, and earnings sharing mechanisms. Traditional regulation and PBR will be described in more depth in the Introduction Section of this paper.

Findings

Policy Staff's assessment finds that Washington's current regulatory framework generally provides an appropriate balance between utility financial stability, customer protections, and achievement of state energy policy objectives. The Commission has already implemented many of the foundational elements commonly associated with performance-based regulation, including MYRPs, revenue decoupling, performance metrics, earnings-

[2] The terms alternative regulation and performance-based regulation are used interchangeably in many settings. However, alternative regulation is an umbrella term for alternatives to traditional regulations. Alternate regulation includes PBR, but also other regulatory alternatives not focused on improving utility incentives. Rosenbach, C., Rebane, K., Goldenberg, C., Walmsley, A., & Proffer, B. (2024). The Nuts and Bolts of Performance-Based Regulation: Tools to Build a More Affordable, Reliable, and Equitable Grid at Slide 3. RMI. RMI Website (last visited June 23, 2026).

sharing provisions, and targeted revenue adjustment mechanisms. These tools collectively support reliability, affordability, equity, and clean energy objectives.

The assessment does not identify a need for a fundamental redesign of the regulatory framework. Instead, the findings support targeted improvements to existing mechanisms to strengthen cost-control incentives, improve regulatory efficiency, reduce administrative burden, and moderate customer rate impacts. In general, mechanisms that advance statutory requirements, customer affordability, safety, reliability, and public policy objectives should be maintained, while certain existing trackers and adjustment mechanisms should be modified, incorporated back into base rates, or periodically reevaluated.

The assessment further finds that the cumulative effect of numerous **trackers**, **riders**, **balancing accounts**, and their corresponding annual adjustment filings has increased regulatory complexity and contributed to more frequent customer bill changes. Opportunities exist to improve transparency, standardize practices, align effective dates, and reduce unnecessary rate volatility without compromising customer protections or utility performance.

Finally, the findings support the Commission's phased approach to PBR. The current framework of goals, outcomes, performance metrics, and guiding principles provides a strong foundation for future consideration of scorecards, targets, and performance incentive mechanisms. Continued evaluation of reported metric data and regulatory outcomes should guide any future expansion of performance-based regulation in Washington.

Introduction

Background and Docket History

On July 30, 2021, the Commission opened Docket U-210590 to initiate this proceeding consistent with the intent of ESSB 5295. All documents and available workshop recordings may be accessed through the Commission's website.

On December 30, 2021, the Commission provided an update to the Legislature, as required by statute, on the progress of the proceeding to date and its expected duration.[3] During the ensuing year (2022), the Commission collaborated with the Regulatory Assistance Project (RAP), culminating in a briefing paper covering best practices and considerations as the Commission prepared to engage with the public.[4] Additionally, the Commission contracted with Great Plains Institute[5] to facilitate the extensive public participation and incorporate comments from those engagements to define regulatory goals, desired outcomes, and design principles, and to identify related metrics[6] as part of Phase 1.[7]

On January 12, 2023, the Commission issued a notice temporarily postponing its activities in this docket given the press of business before the Commission, and the resources necessary to consider issues and fiscal impacts from proposals in the 2023 legislative session.[8]

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[3] The update included an appendix containing a proposed workplan consisting of five phases over the course of several years. Legislative Report and Appendix.

[4] Elaine Prause & Jessica Shipley, *Performance-Based Regulation: Considerations for the Washington Utilities and Transportation Commission*, Regulatory Assistance Project (2022), Available at UTC website.

[5] A Sole Source Contract (Contract 23-SS-39) was executed and posted to the WEBS application and UTC website for public review on Mar. 23, 2022, UTC Contract Search Site (last visited Mar. 25, 2024).

[6] The Commission uses metrics and performance measures interchangeably.

[7] Three workshops were hold on: Apr. 19, Jul. 25, and Nov. 7, 2022. Notice for comments were issued on May 2, Aug. 6, and Nov. 30, 2022; and Jan. 5 and Dec. 13, 2023.

[8] During the 2023 legislative session, the Legislature considered several bills with potential impact on how the Commission regulates certain aspects of utility operations (*e.g.*, ESBH 1329 Preventing utility shutoffs for nonpayment during extreme heat, 2SHB 1032 Mitigating the risk of wildfires through electric utility planning, SSB 5165 Concerning electric power system transmission planning, and ESHB 1589 Supporting Washington's clean energy economy and transition to a clean, affordable, and reliable energy future).

On December 13, 2023, the Commission issued a notice resuming work in this docket. The notice also sought further public engagement and collaboration to refine necessary definitions and calculations as suggested by commenters in response to the notice issued on November 30, 2022.

On April 12, 2024, the Commission issued an interim policy statement providing its general guidance and opinions on PBR, and establishing guiding principles, goals, and a preferred set of metrics. However, the Commission agreed with docket participants that more discussion was needed to define certain terms and calculations for those metrics. Subsequently, on April 18, 2024, the Commission issued a Notice of Workshop and Opportunity to Comment.

On May 28, 2024, the Commission held a workshop to discuss the unresolved metric definitions and calculations and hear feedback from parties related to submitted comments on those issues. Subsequently, the Commission issued its policy statement establishing the initial set of 24 reported performance metrics on August 2, 2024. In addition to other guidance, the Commission provided an expectation for utilities to submit metric data as an appendix to their annual Commission Basis Reports (CBRs).[9]

On May 5, 2025, the Commission issued a Notice of Workshop and Opportunity to Comment, initiating Phase 2 of the proceeding. The notice included questions related to a possible revision to the docket Work Plan and foundational questions to develop guiding principles for designing PIMs.

On June 17, 2025, the Commission held a Workshop to provide a status update on the docket and review the work accomplished to date; review possible updates to the Work Plan; and allow for further discussion of principles and expectations for PIM development. During that workshop, certain parties identified the need for further clarification of reported metrics and their calculations. Additionally, the Commission agreed to revisit possible metrics under Goal 4 (Environmental) and metrics specific to Grid Enhancing Technologies (GETs); prioritize the cost containment strategies topics; and further discuss how financial incentives under PBR interact with the earnings test required under RCW 80.28.425(6).

[9] Commission Basis Reports are required by WAC 480-100-257 (electric) and 480-90-257 (natural gas). The reports are due to the Commission within four months of the end of a utility's fiscal year. Currently, all utilities file by April 30.

On September 4, 2025, the Commission's Policy Staff facilitated a technical workshop[10] to address remaining concerns regarding the clarity of established metric definitions and calculations. Additionally, some discussions regarding Goal 4 and GETs metrics occurred but were held over for future discussion at the workshop scheduled for December 2, 2025.

On October 7, 2025, the Commission issued a Notice of Opportunity to Comment requesting additional responses to a limited number of established metrics in advance of the Commission's final policy statement for Phase 1. Additionally, the Notice provided parties an opportunity to respond to questions related to the cost containment topic.

On December 2, 2025, the Commission held a Workshop to address the existing data available for the proposed Goal 4 (Environmental) metrics and a potential educational workshop on where and how to access that data. Additionally, further discussion was had regarding the Commission's emphasis on promoting cost-effective GETs and the appropriate means to measure utility performance. Finally, a presentation was provided by RMI regarding a utility **cost control** framework based on its recent publication.[11] The Commission provided a detailed explanation of the intent of addressing cost control in the context of this proceeding and its commitment to complete a comprehensive regulatory assessment (*i.e.* the work of this paper).

On December 11, 2025, the Commission issued a Notice of Opportunity to Comment to allow for final comment on the reported metric clarification recommendations and the tentative docket schedule, which included the scoping for the regulatory assessment.

On January 26, 2026, the Commission issued its policy statement clarifying reported performance metrics and addressing performance incentive mechanism principles.

Traditional Regulation

Overview

Generally, ratemaking consists of three distinct components: revenue requirement, cost allocation, and rate design. Ratemaking therefore determines (1) the revenue requirement, or "how much" revenue utilities should collect from customers; (2) "from whom," how much revenue is received from the various classes of customers (*i.e.,* residential,

[10] The Technical Workshop was not recorded, and the Commissioners were not in attendance.

[11] RMI presentation for workshop held on December 2, 2025.

commercial, industrial); and (3) the "how," or rate structure (*e.g.,* basic charge, price per kilowatt hour, demand charges).

Ratemaking is a primary regulatory function that touches all aspects of utility operations. It also has wide-ranging consequences for the various objectives determined by statutory requirements or other public policies, with utility commissions regulating in the public interest. It is the Commission's legal imperative to regulate in the public interest by ensuring safe, reliable, affordable, clean and equitable energy.[12]

The Process

Traditional regulation (also known as rate of return ratemaking or cost of service ratemaking) is the process by which utilities submit an accounting of annual costs (*i.e.,* revenue requirement) to the Commission in periodic rate filings for approval. Utility rates are determined through a formal regulatory proceeding where a utility requests approval to change its rates charged to customers.

The process begins with the filing of the utility's proposal with supporting documentation, followed by discovery and information exchange between parties. Public hearings provide opportunities for public input, while expert testimony and cross-examination help establish the factual record. After deliberation, the Commission issues a final order. These proceedings provide a structured process for determining what costs are prudent and reasonable for recovery through customer rates, establishing a balance between utility financial health and customer protection.

The Revenue Requirement

The **revenue requirement** contains several key components. Operating expenses include **known and measurable** costs such as labor, materials, services, and fuel costs necessary to provide service. Various taxes, including income and property taxes, are also factored in, along with other approved costs such as specific program costs (*e.g.,* energy efficiency). **Rate base** is the physical assets of the utility (*e.g.,* generation plant, power poles, power lines, substations). Utilities are only provided with a return (profit) on the rate base portion of the revenue requirement. The **rate of return** on invested capital is based on the concept of the **cost of capital** (*i.e.,* the compensation that investors require for exposing their capital to risk).

[12] RCW 19.405.010 and RCW 80.01.040.

Revenue requirement formula[13]

Pros and Cons

Traditional regulation has its benefits and shortcomings. The benefits include a limitation on cost recovery to only those expenses that were **prudently** incurred by the utility and are **used and useful** to customers. It also provides an opportunity for the utility to recover reasonable costs and earn a reasonable return. Additionally, cost of service regulation provides a utility more predictable revenues than through a competitive market for utility service. This paradigm ensures customers are protected from **monopoly** price gouging while ensuring safe, reliable service and financially sound utilities.

Criticisms of traditional regulation include a variety of arguments from utilities, consumer advocates, independent power producers, and companies developing emerging technologies. Among these criticisms is that traditional ratemaking does not counter the **throughput incentive**, which means a utility has an incentive to increase sales to earn higher profits. This disincentivizes a utility from investing in conservation or energy efficiency initiatives or other innovative technologies that would decrease sales.

Other Challenges

More recently, utilities have filed more frequent rate cases due to the **regulatory lag** associated with mounting capital investments and inflationary pressures. Frequent rate cases thus create weak incentives for utilities to find cost efficiencies and place high demand on commission staff, the utility, and **intervening parties** (referenced in this paper as administrative burden). This weakened incentive for cost efficiencies results from reduced regulatory lag, allowing utilities to recover expenses through more frequently updated base rates. Contrasted with cost recovery through longer duration of effective rates thus constraining utility cash flows and requiring the utility to manage costs within authorized revenues (similar to a budget). While other criticisms exist, we do not discuss every possible argument but rather provide these two examples for context.

Ratemaking has become progressively more challenging over time because of expanded public policy objectives, layered statutory requirements that are sometimes at odds with each other, climate change, advancing technologies, an increasing number of participants

[13] This is a simplified formula that does not enumerate more detailed subcomponents.

with varying perspectives, and diffuse proceedings in which ratemaking is conducted. This requires regulators to not only comply with statutes or state policies, but also with economic principles, precedent, public acceptability, and the tradeoffs among different objectives.

Figure 1: Traditional versus Emergent Regulatory Objectives

[14]

Alternative Regulation

The term alternative regulation provides a variety of tools that can be used to adjust the regulatory framework to respond to both expanding policy goals and objectives and emerging conditions. Alternative regulation (PBR and its tools) has been increasingly evaluated and adopted to varying degrees by regulatory commissions across the country to mitigate some of the shortcomings of traditional regulation.

[14] Rosenbach, C., Rebane, K., Goldenberg, C., Walmsley, A., & Proffer, B. (2024). The Nuts and Bolts of Performance-Based Regulation: Tools to Build a More Affordable, Reliable, and Equitable Grid. RMI. RMI Website (last visited June 11, 2026).

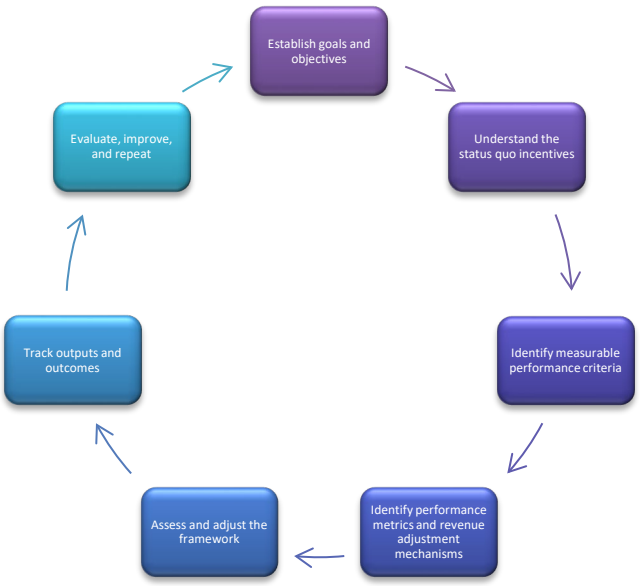
Alternative Regulation Tools

Performance-Based Regulation (PBR) is a regulatory approach that more precisely aligns utilities' financial interests with customer and societal interests. It is typically a system of metrics that tracks utility achievement of specific regulatory and public policy goals – and, in certain cases, attaches financial rewards and penalties to that performance to strengthen value to customers.

PBR can help overcome the limitations of traditional cost-of-service regulation, such as the utility bias for capital investments (also referred to as **capex bias**), promote utility innovation with **advanced technologies**, and provide the flexibility needed to meet state policy mandates and public energy policies. Particularly, the transition to a clean energy future necessitates creative and innovative solutions to meet those required transformational changes for the energy industry.

Best practice for building a PBR framework includes a phased approach. Experience must be gained at each phase with an iterative approach to avoid unintended consequences of flawed framework designs. The graphic below illustrates a sequence that aligns with best practice.[15]

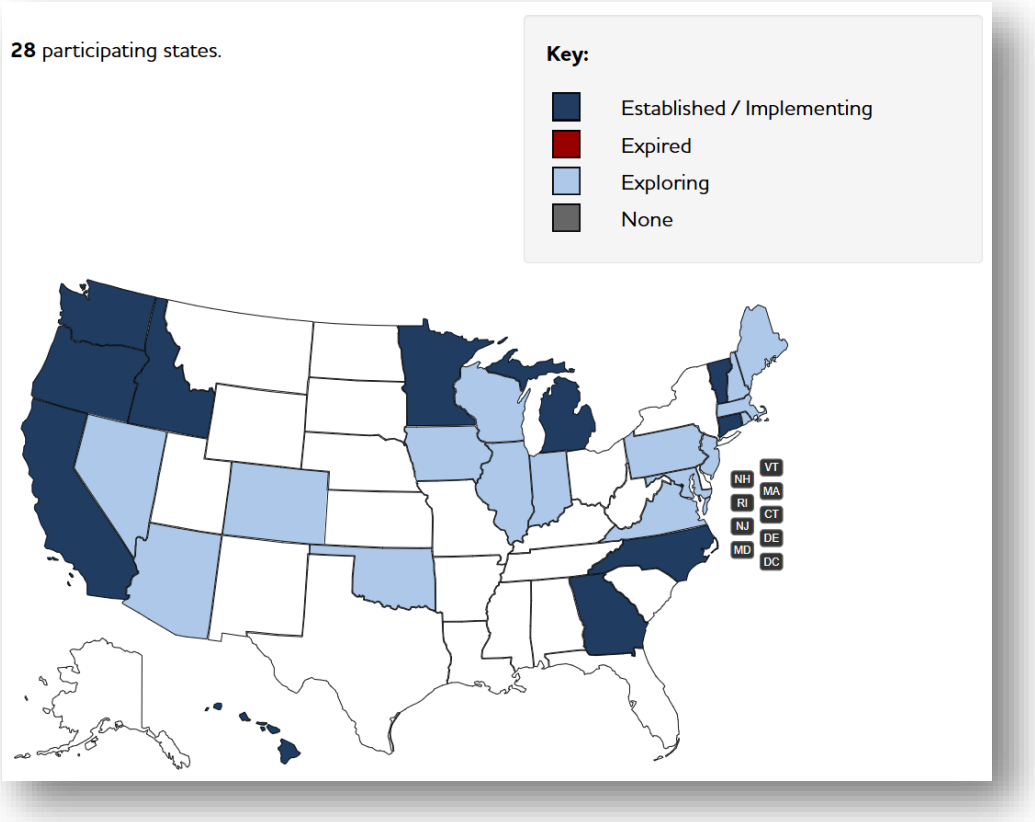
Figure 2: PBR Framework Iterative Process



[15] Graphic reproduced from the report developed by RAP for the Commission.

The graphic below represents states' engagement with PBR as of July 31, 2024.[16] There is a high degree of variation in terms of what PBR mechanisms are employed in each state, how they are designed, and therefore, a high degree of variability in outcomes (which makes it challenging to compare one state's experience with PBR to the next).

Figure 3: National PBR Implementation Status



Multiyear Rate Plans

A common tool used in a PBR framework, MYRPs are mechanisms that set utility base rates and revenue requirement for longer than a single 12-month period. The theory is that the **rate case moratorium** incentivizes the utility to find cost efficiencies during the stay-out period, to operate within their allowed revenues and increase its earnings. A co-benefit of MYRPs is that they can reduce the **administrative burden** associated with annual rate proceedings. This shifts the risk of poor utility cost management to shareholders rather than the customer.

[16] Performance-Based Regulation State Tracking Map - NARUC (last visited June 9, 2026).

MYRPs use some form of an attrition relief mechanism (ARM) and can be structured as either a cap on prices or a cap on revenues, both of which can be adjusted over the MYRP term based on either external indices (*e.g.,* inflation) to account for broader economic circumstances that influence utility costs but are beyond the utility's control, or utility forecasted costs. In some contexts, a hybrid of the two approaches is used.

Under price caps using an external index, the energy, demand, and basic charges are "capped" each year of the rate plan using an inflation rate (typically Consumer Price Index or CPI) reduced by a **productivity factor**. This restricts the cost of energy on the customer bill to predetermined values for each year of the rate plan. The regulator sets the rates for the first year of the rate plan based on more traditional methods and then determines the inflation and productivity factors based on the evidentiary record.

Table 1: Price Cap Example (Residential Customer)[17]

Rate Year	Inflation less Productivity Factor	Basic Charge	Energy Price (kWh)
Year 1		$9.00	$0.1700
Year 2	3.00%	$9.27	$0.1751
Year 3	3.50%	$9.59	$0.1812
Year 4	4.00%	$9.97	$0.1884

However, under a price cap, revenues are not necessarily restricted. A utility's revenue can increase with sales growth, and the converse is also true.

An externally indexed revenue cap structure is similar to the price cap example above as it also includes the inflation and productivity factors. However, the revenue cap formula also includes a growth factor (annual customer growth). This structure is usually paired with a decoupling mechanism to make a utility indifferent to lost revenues from decreased sales (*e.g.,* support conservation and energy efficiency initiatives).[18]

[17] Illustrative example only.

[18] This is also important in Washington, as our utilities recover a portion of their fixed costs through the variable (per kWh charge). Regulatory theory provides that fixed costs are fully recovered through the basic charge. Historically, consumer advocates have urged the Commission to keep a lower basic charge than necessary to recover all fixed costs. The arguments in favor of this policy are to protect low-income customers from having a larger part of their bill unaffected by usage changes. This allows customers to maintain some control over their bills by making energy use decisions. Further, a revenue cap without decoupling is essentially a price cap.

Table 2: Revenue Cap Example (Residential Customer)[19]

Rate Year	Inflation less Productivity	Growth Factor	Basic Charge	Energy (kWh)
Year 1			$9.00	$0.1700
Year 2	3.00%	1.5%	$9.40	$0.1777
Year 3	3.50%	2.0%	$9.92	$0.1875
Year 4	4.00%	1.75%	$10.49	$0.1983

A forecasted MYRP uses the utility's own forecasts of its costs to calculate its requested revenue requirement rather than exogenous factors. The regulator determines the revenue requirement for each year of the rate plan based on company-specific information. This can create some pressure on the utility to acquire cost efficiencies as it cannot file another rate case during the approved MYRP timeframe.[20]

To protect customers against the utility cutting costs that may impact reliability or service quality, regulators typically pair MYRPs with performance metrics and PIMs.[21] There are other elements that can be included or complementary to MYRPs including, but not limited to, **shared savings mechanisms**, **earnings tests**, and **offramps**.[22]

While **general rate cases** may occur less frequently using MYRPs, they may also require more resources to administer. When MYRPs are based on utility forecasts, Commission staff and interested parties are evaluating multiple years of utility costs and supporting information rather than a single year. Alternatively, when MYRPs employ indexed formulas, the issue of setting the variables for inflation, productivity, and other adjustments can be quite contentious. This can strain resources even further when commissions are handling multiple MYRP filings concurrently.

[19] Illustrative example only.

[20] The Commission currently uses a forecasted MYRP. Specific details of our structure are provided in the "Assessment of Current Regulatory Environment" section of this paper. Utilities may still seek rate relief under predefined circumstances, such as approved off-ramps, extraordinary events, significant changes in law or policy, or other Commission authorized situations.

[21] PIMs are discussed in the PBR subsection below.

[22] For more information about MYRPs refer to Appendix E – Additional Resources.

Decoupling

The primary purpose of revenue decoupling (decoupling) is to remove the throughput incentive inherent in traditional cost-of-service regulation. Under traditional ratemaking, utilities have a financial incentive to increase sales volumes because revenues are directly linked to energy consumption. Decoupling mitigates that incentive by allowing utilities an opportunity to recover authorized fixed costs regardless of changes in sales resulting from weather variation, energy efficiency programs, conservation efforts, **distributed energy resources**, or other customer actions. It aims to achieve several goals: (1) mitigating the throughput incentive, (2) supporting conservation and energy efficiency initiatives, and (3) reducing earnings volatility and financial risk for the utility.

The annual adjustments for decoupling are bidirectional, resulting in a **bill surcharge** or **bill credit**. For example, a warm winter with moderate acquisition of conservation and energy efficiencies could result in a refund to customers (rates recovered more revenues than authorized). Conversely, a colder than normal winter with low acquisition of conservation and energy efficiencies could result in a surcharge to customers.[23]

Decoupling, like MYRPs, can use different methodologies (*e.g.,* accrual revenue per customer, current revenue per customer, accrual attrition, and distribution-only). Additionally, there are various forms of decoupling (full, partial, and limited).[24] We will not describe each form and methodology within this paper as it is beyond the scope of this assessment. However, we describe how decoupling is currently employed in Washington in the Assessment of Current Regulatory Environment section.

Performance Incentive Mechanisms (PIMs), Scorecards, and Reported Metrics

When establishing a PBR framework it can be helpful to first establish reported metrics before establishing **targets** (scorecards) or attaching financial incentives (PIMs) to performance, particularly when historical data on an outcome or metric is limited or unavailable. This protects against unintended consequences of incentive structures that are built on assumptions rather than actual data and historical performance.

Reported metrics can be useful to establish baselines and trends (data sets), providing transparency in utility operations. It also assists a regulatory commission in evaluating

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[23] These are not the only factors that may impact the decoupling adjustment but serve as an example of the bidirectional functionality of the mechanism.

[24] Lazar, J., Weston, F. Shirley, W., Midgen-Ostrander, J., Lamont, D., & Watson, E. (2016). Revenue Regulation and Decoupling: A Guide to Theory and Application. Regulatory Assistance Project website (last visited June 6, 2026).

utility operational efficiency and financial health during MYRPs. There is no financial reward or penalty attached to reported metrics.

Targets used in scorecards or PIMs can be based on reported metric data sets or other readily available sources to establish an acceptable range of results. As with reported metrics, there is no financial reward or penalty attached to performance against scorecards. Like reported metrics, scorecards can support comparability against a desired outcome or across utilities and promote transparency. Additionally, scorecards can create a "reputational incentive" to determine whether or not an improvement or maintenance of desired performance can be achieved without a financial incentive.

Performance Incentive Mechanisms, or PIMs, tie utility performance against a specified metric and target to a portion of its revenue. There are various methods available to establish a PIM (*e.g.,* savings sharing mechanisms, **equity adders**, specific dollar rewards or penalties, symmetrical or asymmetrical structures, upside-only or downside only). We will not describe each design variant within this paper as it is beyond the scope of this assessment.

Shared Savings Mechanisms

A shared savings mechanism (SSM) is a type of PIM that allows customers and the utility to share in savings achieved with a specific action or program. Some examples of expenditures where SSMs can be applied include energy efficiency programs, **non-wires** and **non-pipes** solutions, **grid enhancing technologies**, construction costs, and fuel cost variability.[25]

TOTEX

Unlike traditional regulation, totex regulation allows utilities to earn a return on both capital investments and operating expenses. It eliminates the traditional bias toward building infrastructure and promotes the selection of the best-fit solution in meeting energy needs. However, there is still a timing difference in how those two buckets of costs (capital and operating) are recovered. In the UK, these buckets are referenced as "fast money" and "slow money." Fast money is treated like operating expenses under traditional cost-of-service regulation (*i.e.,* it functions as a pass-through to customers). Slow money is treated like capital expenditures (*i.e.,* it is added to rate base and depreciated), just as done under

[25] *See* Wilson, G., Whited, M., Havumaki, B., Lane, C., & Goldenberg, C. (2025, November 3); Fixing Multiyear Rate Plans. RMI website (last visited June 6, 2026).

traditional regulation. Both buckets contain capital and operating expenditures based on a predetermined capitalization rate. [26]

Totex ratemaking has not been adopted by any regulatory commission in the United States. Some utilities have argued that implementation of totex may violate **Generally Accepted Accounting Principles** (GAAP). Any adoption of this tool would be a case of first impression and would require considerable evaluation likely requiring consultant expertise.

Commission's framework decisions to date

Over the past few years, the Commission through extensive public engagement established its basic PBR framework. This includes: the goals and objectives, guiding principles for metric design, reported metrics, and PIM design principles. In Puget Sound Energy's (PSE's) 2022 MYRP, the Commission authorized the only currently established PIM as part of a multiparty settlement. Each of the framework components are provided in detail below.

Goals and Outcomes

The Commission established four policy goals with 15 outcomes.

Goal 1: Resilient, reliable, and customer-focused distribution system

Outcomes:

1. Ensure utility responsiveness to customer outages and restoration times.
2. Utilities are prepared for and respond to outages and other impacts caused by cyberattacks, significant events, wildfires, extreme weather events, and other natural disasters.
3. Resilient infrastructure and service, including distributed energy resources, to enable customers to maintain essential functions during times of potential outages.

Goal 2: Customer affordability

Outcomes:

1. Reduce energy burden for customers experiencing high energy burden, especially those in Highly Impacted Communities, Vulnerable Populations, and low-income customers.

[26] Rosenbach, C., Rebane, K., Goldenberg, C., Walmsley, A., & Proffer, B. (2024). The Nuts and Bolts of Performance-Based Regulation: Tools to Build a More Affordable, Reliable, and Equitable Grid at Slide 25. RMI. RMI Website (last visited June 24, 2026).

2. Maximize utilization of cost-effective distributed energy resources and grid-enhancing technologies.
3. Maximize the benefit and efficiency of the energy assistance process so that support can be provided to customers based on the program resources available.
4. Lowest reasonable compliance with public policy goals and environmental requirements.
5. Increase awareness of and equitable access to utility services, assistance, education, and benefits for all customers, with a focus on Highly Impacted Communities, Vulnerable Populations, and low-income customers.

Goal 3: Equitable Utility Operations

Outcomes:

1. Equitable and diversity-focused utility hiring, promotion, and vendor selection practices.
2. Ensure that utility operational and investment decisions promote equitable service that does not unfairly harm or disadvantage Highly Impacted Communities, Vulnerable Populations, and low-income customers.
3. Equitable access to all utility energy programs, including those related to energy efficiency, demand response, and distributed energy resources.
4. Ensure active and meaningful engagement with communities, including Highly Impacted Communities, Vulnerable Populations, and low-income customers such that their input is considered in utility planning processes.

Goal 4: Environmental improvements

Outcomes:

1. Reduce pollution burden and pollution exposure with a focus on communities with elevated exposures to health hazards, including Highly Impacted Communities, Vulnerable Populations, and low-income customers.
2. Cost-effective alignment of load with clean energy generation and storage through load management, energy efficiency measures, and demand response.
3. Accelerate the cost-effective achievement of Commission or state public policy goals and statutes, including the reduction of greenhouse gas emissions.

Metrics

Guiding Principles for Metric Development

Table 3: Guiding Principles for Metric Development

Principle	Description
Directly related to policy goals and the public interest	All metrics will clearly communicate the regulatory goals and desired outcomes and describe how the public interest will be met. Metrics can provide for outcomes that go beyond rule, statute, or regulatory requirements where said results are cost effective and in the public interest.
Equity forward	Metrics will be used to advance equity. Equity has historically not been considered as a component of the public interest standard, but it is an essential element of performance-based regulation. Metrics will neither conceal nor obscure inequities.
Outcomes based	Metrics should track outputs and outcomes, not inputs. While the Commission may consider in specific cases metrics that track inputs, the proponent must demonstrate clearly that such metrics are appropriate.
Clearly defined, articulated, and understandable	The method for calculating metrics and specific data used for such calculations should be unambiguous and not subject to interpretation, to provide meaningful comparison and protect against disputes. Metrics should be accessible and understandable to the public.
Use reasonably available and verifiable data with clearly defined calculations	Metrics will use data that can be reasonably obtained, is transparent, and easily verifiable by Commission staff and external interested persons including the public. Metrics should not use confidential data or proprietary models that reduce the transparency or accessibility of data. If proprietary models are used, those relying on models should provide access to the models or rerun the models using information from interested persons. The method for calculating metrics and input data used should be unambiguous and not subject to interpretation to provide meaningful comparison and protect against disputes.
Allow for regular, consistent, accessible reporting and periodic evaluation	Metrics should be designed to accommodate regular reporting (*e.g.,* annually). Utilities will ensure metric reporting is communicated to customers and the public in an equitable and accessible way, including attention to readability and translation, in a manner consistent with Commission rules, specifically WAC 480-07-140(6).

Principle	Description
Reasonably within the utility's control	Metrics will seek to measure factors that are reasonably affected by the utility's actions and not be entirely based on external influences (*i.e.,* market prices, weather, mean area median incomes) without limiting the Commission's authority and to the extent they do not hinder the advancement of equity and energy justice.
Promote regulatory efficiency	The number of metrics should be no greater than that necessary to measure performance towards major goals and outcomes while ensuring the ability to obtain valuable data in the public interest.

Current Metrics[27]

LEGEND

(G) Goal
(O) Objective
(E) Electric
(NG) Natural Gas

Table 4: Metrics and Descriptions

Metric	Description	G/O	E/NG
Equity in Reliability: length of power outages	Average and median length (in minutes) of power outages per year, separately calculating Named and Non-named Communities reporting with and without major event days (MEDs).	G1 O1	E
Historically Worst Performing Circuits	The 10 worst performing circuits in any given year separately by both frequency and duration, reported both with and without MEDs and identifying circuits that serve Named Communities. In addition, of the 10 worst performing circuits (separately by frequency and duration), the number of years over the past five years that a circuit has appeared on the list.[28]	G1 O1	E
Natural Gas emergency response time	Average and median length (in minutes) from notification to arrival of field technician in response to natural gas system emergency, separately reported for Named and Non-named Communities.	G1 O2	NG
Customers Experiencing Multiple Interruptions (CEMI) for Named and Non-named Communities	Average number of outages for customers experiencing multiple interruptions (grouped by those experiencing 1-4 interruptions, 5-8 interruptions, and nine or more interruptions) calculated as the total number of customers with sustained interruptions of greater than five minutes divided by the total number of customers served. Provide this calculation both with and without MEDs for the service area as a whole and separately reported for Named and Non-named Communities.	G1 O3	E

[27] Reported annually no later than April 30.

[28] This is reported through **SAIDI** and **SAIFI** measures.

Metric	Description	G/O	E/NG
Customers Experiencing Long Duration Outages (CELID) for Named and Non-named Communities	Number of unique customers experiencing more than eight hours of consecutive interruption per year, providing separate calculations both with and without MEDs for the service territory as a whole and separately for Named and Non-named Communities.	G1 O3	E
Arrearages per Month	Number of customers in arrears by period and total amount of arrearages by month, by class, measured by census tract to include 30+, 60+, and 90+ days in arrears for total company, and electric and natural gas separately for dual fuel utilities.	G2 O1	E/NG
Percentage of customers in arrears with Arrearage Management Plan (AMP)	By census tract and monthly, the number of residential customers in arrears with arrearage management plans divided by total customers in arrears.	G2 O1	E/NG
Average Energy Burden	Annual residential bill divided by area median income by census tract for all customers, comparing outcomes in Named and Non-named Communities. For dual fuel utilities, electric and natural gas service should be stated separately calculated both before and after energy assistance. Also provide the number and percentage of customers experiencing high energy burden by census tract.	G2 O1	E/NG
Net Benefits of Distributed Energy Resources (DERs)	Net present value of benefits and cost-effectiveness ratio of DERs as measured through a Commission approved cost-benefit analysis.	G2 O2	E
Distributed Energy Resource Availability and Utilization	Annual energy (MWh) produced, consumed, or discharged from dispatchable distributed energy resources (DERs) by program; Annual capacity (MW) from DERs by program; and aggregated annual capacity of DERs providing additional grid services through utility programs.	G2 O2	E
Utility Assistance Program Effectiveness	Percentage of estimated low-income needs met with dispersed funds from customer-funded assistance programs on an annual basis.	G2 O3	E/NG

Metric	Description	G/O	E/NG
Annual utility revenues and rate impacts	Annual revenue from base rates approved in most recent MYRP by customer class; Total incremental or decremental revenue from all approved rate adjustments, excluding those authorized by the MYRP, occurring during the reporting year separated by schedule and customer class providing the calendar month and percentage of the change for each schedule; Net bill revenue (annual) by schedule.	G2 O4	E/NG
Customers who participate in one or more bill assistance programs	The number and percentage of estimated low-income customers who participate in one or more customer-funded energy assistance programs, both aggregated and by census tract; and separately the number and percentage of estimated low-income population enrolled in a utility bill discount program and total amount of discount applied annually.	G2 O5	E/NG
Workforce Diversity	Percentage of employees and senior management (separately identifying: (a) C-suite employees, (b) directors and employees more senior than directors, and (c) the remaining workforce who identify as: (i) a person of color; and/or (ii) a woman or non-binary; Percentage of total employees that opt out from providing information either through HR data or surveys.	G3 O1	E/NG
Supplier Diversity	Percentage of suppliers that self-identify as owned by people of color, women, veteran, and other marginalized groups, and total dollar amount and percentage of total company spend to those suppliers.	G3 O1	E/NG
Equity in Distributed Energy Resource Programs	Number of customers in Named Communities and separately known low-income customers enrolled in each utility DER program (providing a separate calculation for energy efficiency, electric transportation, net metering, and demand response) divided by total customers enrolled in each program.	**G3 O3**	E
Equity in Distributed Energy Resource Program Spending	Separately calculated percentage of utility spending on demand response and distributed energy resources (energy efficiency, electric transportation, and renewables) that benefit Named Communities as compared to Non-named Communities.	**G3 O3**	E

Metric	Description	G/O	E/NG
Operational Efficiency	O&M total expenses divided by operating revenue	**MYRP**	E/NG
Operational Efficiency	Operating revenue divided by Average of Monthly Averages (AMA) total rate base and End of Period (EOP) total rate base	**MYRP**	E/NG
Operational Efficiency	Current Assets divided by Current Liabilities	**MYRP**	E/NG
Earnings Metric	Net Income divided by Operating Revenue	**MYRP**	E/NG
Earnings Metric	Retained Earnings divided by Total Equity	**MYRP**	E/NG

PIMs

PIM Guiding Principles

Table 5: PIM Principles and Descriptions

PIM Principles	Descriptions
Alignment with Policy Goals and Outcomes	PIMs should be clearly and directly tied to articulated state or regional policy goals and desired regulatory outcomes. The Commission favors PIMs that: address outcomes that are not already fully incentivized through existing regulatory mechanisms; support objectives such as reliability, resiliency, affordability, regulatory efficiency, equity, decarbonization, or customer service; or promote new technologies that support those objectives; focus on outcomes rather than inputs or activities, while appropriately accounting for external factors beyond the utilities' control; and promote regulatory efficiency, including where a single PIM may satisfy multiple regulatory outcomes. PIMs should not reward utilities for meeting basic statutory, regulatory, or contractual obligations, except where a penalty-only structure is warranted.
Clarity, Measurability, and Verifiability	To ensure transparency and accountability, PIMs should be clearly defined, with unambiguous performance metrics, baselines, targets, and formulas; quantifiable using reasonably available, reputable, and reliable data; measurable and independently verifiable using transparent methodologies; and easily interpreted by the utilities, the Commission, and other interested parties including the public. Data underlying PIMs should, to the extent practicable, be publicly available and subject to audit or review.
Utility Control and Achievability	PIMs should be designed such that performance outcomes are substantially within the utility's control or influence. The Commission will consider whether; performance targets are achievable yet sufficiently ambitious to motivate improved performance beyond business-as-usual; external risks and uncertainties are appropriately accounted for in metric design and calibration; and utility-specific circumstances are considered, with general guidance applied through utility-specific proceedings such as general rate cases.

PIM Principles	Descriptions
Balance of Risk, Reward, and Customer Benefits	PIMs should promote a fair balance between utility financial incentives and tangible customer and societal benefits. In evaluating this balance, the Commission will consider: the magnitude of rewards and penalties relative to the level of utility control and risk assumed; the cumulative financial exposure associated with multiple PIMs; benefit cost analyses; where appropriate, including consideration of shared-savings approaches; rate and bill impacts, with attention to affordability; and whether incentives are proportionate and do not unduly reward or penalize utilities at the expense of customers. Equity considerations should be embedded in PIM design, including mitigating burdens and prioritizing benefits for Named Communities or low-income customers, where relevant.
Integration with the Broader Regulatory Framework	PIMs should be thoughtfully integrated within the existing regulatory framework and PBR structure. The Commission favors PIMs that: complement, rather than duplicate or distort, other regulatory mechanisms such as decoupling, cost trackers, or MYRPs. PIM proposals are considered through general rate cases and are not subject to the earnings test under RCW 80.28.425(6).
Incentive Structure and Calibration	The Commission recognizes that no single incentive structure is appropriate for all circumstances. PIMs may be designed as reward, penalties, or symmetrical mechanisms, depending on the policy objective and risk profile. In all cases: incentives should be calibrated to motivate meaningful performance improvements without imposing undue burdens on customers; the choice between symmetrical and asymmetrical structures should be justified based on the desired outcome; and incentive formulas should be consistent with and supportive of the intended policy results.
Adaptability, Review, and Safeguards	PIMs should be adaptable and subject to periodic review to ensure continued effectiveness. The Commission expects that: PIMs may evolve over time based on observed performance, data quality, and changing conditions; initial PIMs should be set conservatively, with adjustments informed by experience; safeguards should be included to minimize gaming, unintended consequences, or the optimization of incentivized metrics at the expense of non-incentivized metrics or outcomes; and

PIM Principles	Descriptions
	performance results should be reported through transparent, publicly available scorecards or similar tools.

Currently Authorized PIMs

Puget Sound Energy

Demand Response (DR) PIM

Established a target of 207 MW from its DR program providing at least 30 percent of the DR energy benefit to Named Community customers. The incentive is capped at $1M based on the average of three ratios: (1) the percent of additional benefits going to Named Communities above the 30 percent threshold, (2) the percent of additional DR MWs acquired beyond the 207 MW target, and (3) PSE's weighted cost of capital percentage from its 2024 GRC [Rate Year 1: 7.52% and Rate Year 2: 7.62%]. The PIM is only approved through the end of the current rate plan ending January 2027.

Figure 4: PSE DR PIM Structure

% of **Additional** DR for Named Communities above 30% Achieved	% of **Additional** DR above 207MW Achieved	PIM Reward
0%	0%	$0
Greater than 0%	0%	$0
0%	Greater than 0%	$0
Greater than 0%	Greater than 0%	$\left(\frac{Sum\ of\ three\ Ratios}{3}\right) * DR\ program\ costs$

Assessment of Current Regulatory Environment

The information provided below represents Policy Staff's perspectives on the mechanisms currently in use for Commission-regulated energy utilities. We provide a summary description of each mechanism (specific to Washington) followed by a brief assessment of how the mechanism supports, is neutral, or contradictory to utility cost control. This paper contains a summary of more detailed analysis. Refer to Appendix A for the more comprehensive evaluation of each mechanism.

Additionally, we identify why a particular mechanism may or may not be warranted for other policy reasons. For example, a mechanism may be contradictory for cost control but supports administrative efficiency, state mandates, or policy compliance.

Next, we provide areas that may require additional attention. Based on the analysis of five years of historical data (Refer to Appendix B), and research into the history and conditions surrounding each mechanism (Refer to Appendix A and D), we provide recommendations for each mechanism (summarized in Appendix C). Where recommendations include an adjustment to the effective date please refer to the Tracker Mechanism Principles section of this document.

Multi-Year Rate Plans

[Avista, Cascade, NW Natural, PacifiCorp, PSE]

Description

Washington law requires electric and natural gas utilities to propose MYRPs as part of general rate case proceedings.[29] The Commission may approve plans extending up to four years and establish annual revenue requirements, authorize operating expenses, and associated ratemaking adjustments throughout the plan period.

Washington's implementation of multi-year rate plan structures to date has relied primarily on utility forecasts to establish a revenue cap for terms of 2-4 years. Capital investments anticipated during the rate plan period are incorporated through **provisional plant** adjustments, while the statutory annual earnings tests provide customer protection against a utility significantly overearning during the rate plan. [30]

Assessment

MYRPs can support cost control objectives by creating longer periods between comprehensive rate reviews. In theory, limiting the frequency of rate cases encourages utilities to manage costs efficiently because opportunities to seek additional revenue recovery are reduced. Further, MYRPs support cost control by establishing a revenue or price cap, thereby creating a budget for utilities to work within.

However, Washington's current implementation retains many characteristics of traditional cost-of-service regulation, paired with multiple revenue adjustment mechanisms, and therefore provides weaker efficiency incentives than some alternative MYRP structures

[29] *See* RCW 80.28.425.

[30] The earnings test provides that if a utility earns more than 0.5% high than its most recently authorized rate of return (in a calendar year), it must defer all revenues above that threshold. Those deferred over earnings are returned to customers when authorized by the Commission in a future proceeding. In other jurisdictions, this is referred to as an earnings sharing mechanism.

used in other jurisdictions. Washington's utilities continue to forecast future capital expenditures and operating expenses for inclusion in rates, while annual provisional plant reviews provide opportunities to ensure the plant included in rates is both prudent and used and useful. A refund may be ordered if the provisional plant review identifies imprudent investments, plant not serving customers, or underspends the authorized amount **embedded in rates**.

The current framework preserves important customer protections by maintaining **prudency reviews**, used-and-useful standards, known-and-measurable requirements, and earnings-sharing provisions. These protections reduce the risk that customers will pay for imprudent or unnecessary investments.

At the same time, the combination of forecasted expenditures, provisional plant treatment, and **portfolio-level review** may create incentives for utilities to forecast higher capital spending levels than ultimately necessary. The resulting review process also creates substantial administrative burden for utilities, the Commission, its staff, and intervenors.

Overall, Washington's current MYRP structure somewhat supports cost control objectives but does not fully capture the efficiency benefits commonly associated with PBR.[31]

Issues for Attention

The primary issue is whether the existing structure appropriately balances customer protection with incentives for utility efficiency. Current provisional plant review processes require significant annual resources while still allowing considerable flexibility in utility capital spending decisions.

Additional attention should be given to longer-term treatment of operating expenses, particularly as rate plans extend to three and four years. Inflationary pressures and changing operating conditions may require greater consideration of escalation methodologies while preserving incentives for cost management.

The interaction among MYRPs, earnings-sharing provisions, provisional plant adjustments, and cost trackers should also be evaluated holistically since multiple annual review

[31] Appendix A provides a neutral score given the relatively short length of previous MYRPs and some of the criticisms outlined in that more detailed analysis.

mechanisms outside of the rate case reduce the efficiency incentives that multi-year plans are intended to create.

Recommended Action

Maintain the current MYRP framework in the near-term while continuing to evaluate its effectiveness and alternative designs.

The Commission should evaluate whether the current structure produces measurable cost containment benefits and whether modifications to provisional plant treatment, earnings-sharing provisions, or operating expense treatment may strengthen efficiency incentives. The Commission should incorporate these considerations and decide whether the proposed MYRPs are suitable to support cost containment within the pending **adjudications**.[32] If these issues are not resolved through those proceedings, the Commission should initiate a comprehensive review within the PBR docket in 2027.

Revenue Decoupling

[Avista, Cascade, PacifiCorp, PSE]

Description

Revenue decoupling is a regulatory mechanism that separates a utility's recovery of authorized **fixed costs** from the volume of energy sold. Washington currently authorizes decoupling mechanisms for Avista, Cascade Natural Gas, PacifiCorp, and Puget Sound Energy. Under these mechanisms, annual true-up adjustments reconcile the difference between **authorized delivery revenues** and actual revenues collected from customers. Overcollections are returned to customers while under collections are recovered through future rates.[33]

In Washington, **full decoupling** was authorized when this mechanism was established for each affected utility. Over time there have been minor modifications to the mechanisms. For example, in 2021, PSE realigned the **rate schedules** subject to decoupling.

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[32] This is dependent on the evidence and testimony provided by the respective utilities, parties, and intervenors in each specific adjudication. Policy Staff are not a party to adjudications and therefore the analysis contained in this policy paper is not considered in Commission decisions in those cases.

[33] To review of an example of the steps taken in calculating the adjustment refer to Avista Schedule 75.

Additionally, the decoupling earnings test has been reset to mirror the MYRP statutory earning test.[34]

The annual adjustments are subject to a cap on rate increases.[35] If the incremental amount of the proposed surcharge exceeds the cap, any remaining **deferral** is carried over to the following year. There is no limit if the adjustment is in the rebate direction.

Decoupling mechanisms were originally approved for a limited period and subject to evaluation. However, some have been 'permanently' implemented while others are coming to the end of a formal evaluation period. For example, Avista's mechanism is authorized until the end of its current MYRP. The mechanism must be adopted in the MYRP currently before the Commission to remain in effect.[36]

Assessment

Revenue decoupling generally supports utility cost control and affordability objectives. By reducing the throughput incentive, decoupling removes a fundamental conflict between utility financial interests and public policy goals that encourage conservation such as, energy efficiency, **demand response**, distributed energy resources, and **beneficial electrification**. Decoupling also improves revenue stability and provides greater certainty for long-term planning under MYRPs.

The mechanism allows utilities to pursue conservation and efficiency programs without concern that successful implementation will reduce revenues needed to recover fixed costs. This is particularly important as Washington advances efforts to meet the **Clean Energy Transformation Act** requirements and broader **decarbonization** policies.

From a customer perspective, annual adjustments are generally smaller than full rate cases and allow customers to receive benefits associated with higher-than-forecast sales through refunds rather than waiting until the next general rate case. The mechanism therefore protects customers from utility windfalls associated with **electrification** growth or unusually high sales volumes. However, annual true-up adjustments, though small, can still contribute to rate volatility and administrative burden because utilities, Commission Staff, and stakeholders must review and process annual filings.

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[34] These are not all-inclusive examples.

[35] PSE and PacifiCorp have a five percent cap. Cascade and Avista have a three percent cap.

[36] *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-240006, UG-240007 (*Consolidated*), Order 08 at ¶¶ 752-757(Dec. 20, 2024).

At the same time, decoupling does not guarantee utility earnings and does not eliminate all utility incentives related to sales growth. Utilities continue to benefit from activities that increase energy usage, such as electrification initiatives, even though the throughput incentive is reduced.

On balance, decoupling remains an effective mechanism that aligns utility incentives with conservation, efficiency, and decarbonization objectives while supporting stable utility operations.

Issues for Attention

Revenue decoupling has significant interactions with several major regulatory mechanisms. The mechanism complements MYRPs by providing an annual reconciliation process that reduces pressure to reopen approved rate plans when sales volumes differ from forecasts. Decoupling also supports **Integrated Resource Planning** by allowing utilities to focus on long-term resource optimization rather than short-term sales growth.

The mechanism is closely connected to **Clean Energy Implementation Plans** because achievement of energy efficiency and conservation targets could otherwise reduce utility revenues. As utilities increasingly pursue electrification, **demand-side management**, and distributed energy resources, maintaining alignment between decoupling design and state policy objectives becomes increasingly important.

The treatment of **carrying costs** warrants further attention. Currently authorized carrying costs vary among utilities and can materially increase customer bill impacts when significant balances accumulate. Additionally, annual adjustment effective dates currently occur during periods of higher customer energy usage for some utilities, potentially amplifying customer bill impacts during **peak seasons**.

Recommended Action

Maintain revenue decoupling as a core regulatory mechanism but modify the carrying cost calculation used for decoupling balances to utilize each utility's **after-tax cost of debt**. This approach better reflects actual financing costs specific to each utility while reducing upward pressure on customer bills.

Additionally, the Commission should also consider standardizing effective dates during shoulder seasons to reduce customer bill impacts during periods of peak energy consumption.

Finally, the Commission should encourage consideration of a decoupling mechanism for Northwest Natural to improve consistency among regulated natural gas utilities.

Power Cost Adjustment Mechanisms

[Avista, PacifiCorp, PSE]

Description

Washington's electric utilities utilize Power Cost Adjustment Mechanisms (PCAMs)[37] and similar structures to reconcile differences between forecasted power costs established in rates and actual power costs incurred. These mechanisms generally include **dead bands** and **sharing bands** that allocate a portion of the power cost risk between customers and **shareholders**.

Annual filings calculate over- or under-recoveries relative to **authorized baseline costs** and adjust customer rates accordingly. These mechanisms are intended to address volatility in power markets while maintaining incentives for prudent power cost management.

Assessment

PCAMs generally support cost control because they do not provide direct dollar-for-dollar recovery of all power costs. Existing sharing mechanisms preserve utility exposure to a portion of cost variability and therefore create incentives for efficient **resource planning**, **forecasting**, **procurement**, and **portfolio management**.

The mechanisms can protect customers by ensuring that power costs embedded in rates are periodically reconciled with actual costs. Customers receive the benefit when actual costs are lower than forecasted, while utilities recover only a portion of the costs that exceed the authorized levels through the sharing bands. This structure protects customers to some degree from forecasting variances and extreme events that impact wholesale energy prices.

However, recent experience suggests that forecasting accuracy and power cost volatility deserve additional scrutiny. Many annual adjustments have resulted in customer surcharges, raising questions about whether existing **forecasting methodologies** and incentive structures remain appropriate under evolving market conditions.

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[37] Avista's mechanism is called the Energy Recovery Mechanism, or ERM.

Although utilities frequently argue that many power cost drivers are beyond their control, utilities make business decisions about their energy portfolios, procurement strategies, and whether to join an **energy market,** as examples. However, we recognize that changing resource portfolios, increased renewable penetration, market volatility, and evolving load forecast methodologies suggest a need to reassess whether current risk allocation continues to produce desired outcomes.

Issues for Attention

The Commission has observed significant variances between power cost forecasts established during rate proceedings and actual costs subsequently reported through annual adjustment filings. These variances may indicate opportunities to improve forecasting practices or modify adjustment structures.

The interaction between PCAMs and MYRPs is particularly important because power cost baselines established through forecasts may become increasingly uncertain over longer planning horizons. There may also be reasons to review the consistency of forecasting and modeling across docket types (*e.g.,* utilities may use different timelines/assumptions when forecasting in IRPs versus fuel dockets).[38]

Differences in carrying cost treatment among utilities also warrants attention. Current practices are inconsistent and may result in materially different customer outcomes despite similar underlying circumstances.

Recommended Action

Maintain existing mechanisms pending resolution of issues currently being considered in active adjudications. The Commission should continue evaluating whether structural modifications are necessary to improve forecasting accuracy and strengthen incentives for prudent power cost management, particularly if the Commission begins approving longer-term MYRPs.

Consistent with recent Commission policy guidance, carrying costs should be standardized using each utility's after-tax cost of debt to improve consistency and better align carrying costs with actual financing costs.

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[38] This is not a statement of confirmation but one for future verification.

Purchased Gas Adjustment Mechanisms

[Avista, Cascade, NW Natural, PSE]

Description

Purchased Gas Adjustment (PGA) mechanisms allow natural gas utilities to recover the actual cost of procuring natural gas supplied to customers. Washington's regulated gas utilities use PGA mechanisms that include both a forecasted **commodity cost** component and an annual true-up process that reconciles actual costs with amounts recovered through rates. Under current practice, customers receive refunds when costs are lower than forecasted and pay surcharges when costs exceed forecasted levels.

Historically, the Commission has treated commodity costs differently from other utility expenses because utilities have limited control over **wholesale natural gas market** prices. The Commission's 2017 Policy Statement regarding hedging practices established expectations for risk-responsive hedging strategies and encouraged utilities to actively manage commodity price risk.[39]

Assessment

PGA mechanisms generally support customer affordability and cost control objectives because customers ultimately pay no more and no less than the utility's actual prudently incurred gas commodity costs. The mechanism protects utilities from financial exposure associated with volatile commodity markets while ensuring customers receive the benefits of lower-than-forecasted prices.

Unlike electric power cost mechanisms, PGAs provide a nearly complete pass-through recovery of commodity costs. This substantially reduces utility financial exposure and limits incentives for utilities to pursue cost minimization beyond prudent procurement and hedging practices.

The Commission's previous emphasis on **risk-responsive hedging** has improved utility risk management and provided customers with additional protection from extreme market events. Nevertheless, the mechanism places nearly all commodity price risk on customers despite customers having no control over those costs.

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[39] Policy and Interpretation Statement on Local Distribution Companies' Natural Gas Hedging Practices, Docket UG-132019 (Mar. 13, 2017). The policy statement is available on the Commission's website.

Overall, the mechanism remains appropriate because commodity costs are largely beyond utility control. However, the current structure may not provide an optimal balance between customer and shareholder risk.

Issues for Attention

Recent discussions have raised questions regarding whether a modest risk-sharing component (**risk-sharing mechanism**) should be incorporated into PGA structures. While utilities have limited ability to control commodity prices, they do exercise judgment regarding hedging strategies, **storage utilization**, **transportation arrangements**, and operational responses during periods of market volatility.

The annual timing of PGA adjustments also warrants attention. Most adjustments become effective shortly before the winter heating season when customer consumption is highest. This timing can amplify customer bill impacts during periods of greatest affordability concern.

Additionally, commodity costs flowing through PGAs increasingly include costs associated with broader public policy requirements, including certain **Climate Commitment Act**-related expenses.

Recommended Action

Modify the current PGA structure to incorporate a limited risk-sharing mechanism. A 90/10 customer-shareholder allocation above an established threshold would better balance utility and customer interests while preserving the fundamental purpose of the mechanism.

The Commission should also consider moving annual PGA effective dates to reduce customer bill impacts during winter peak usage periods.

Further, we recommend continuing the focus on risk-response hedging practices. Specifically, requiring utilities to provide an update of any changes to its risk-responsive hedging strategies through general rate case testimony. Following periods of extreme market volatility, utilities should provide informational briefings or reports describing market conditions, mitigation measures employed, and lessons learned.[40]

[40] This could be completed through a recessed open meeting as an informational briefing.

Renewable Energy Credit Tracker

[Avista, PSE]

Description

Renewable Energy Credit (REC) trackers pass through proceeds associated with REC sales to customers. Currently, Avista and PSE maintain REC tracking mechanisms that annually reconcile those generated revenues.

The mechanism was developed in the context of Washington's **Energy Independence Act**, which requires qualifying utilities to obtain a specified portion of their electricity from eligible renewable resources and utilize RECs as a compliance tool.

Assessment

The REC tracker has little direct impact on utility cost control. The mechanism neither creates meaningful incentives for utilities to increase or decrease spending nor materially influences utility operational decision-making.

The relevance of REC trackers has diminished as Washington utilities work toward compliance with the Clean Energy Transformation Act (CETA). We anticipate that utilities will increasingly retire RECs to demonstrate achievement of clean energy requirements rather than generating surplus RECs available for sale.

The primary purpose of the tracker is accounting transparency. Customers receive the benefit of proceeds associated with REC sales rather than utilities retaining those revenues. This mechanism functions largely as a **pass-through accounting** adjustment with annual bill impacts becoming smaller and less frequent. In fact, PSE has already set its tracker to zero, and with the associated revenues and costs embedded and reflected in the power cost baseline, starting in 2025. [41] Policy Staff find no practical value in maintaining a separate tracking mechanism for this purpose.

[41] PSE's 2024 REC tariff filing cover letter (Advice No. 2024-45) in Docket UE-240837 filed on Nov. 1, 2024. The Commission allowed to tariff revision to be become effective at its Open Meeting held on Dec. 19, 2024.

Issues for Attention

The Commission should evaluate whether the administrative effort associated with annual filings and reviews remain justified given the declining likelihood of significant REC sales.

Recommended Action

Eliminate REC trackers and incorporate any future REC-related revenues or costs into existing power cost recovery mechanisms or **base rates**.

Should significant REC sales occur in the future, utilities can address those revenues through existing ratemaking processes without maintaining a separate annual tracker.

Clean Energy Implementation Plan Tracker

[Avista, PSE]

Description

The Clean Energy Implementation Plan (CEIP) tracker provides recovery of costs associated with the implementation of CETA requirements. The tracker covers activities such as public engagement, data collection for **Customer Benefit Indicators** (CBI), administration of **Named Communities Investment Fund**, and other implementation activities.

Currently, Avista utilizes an annual CEIP tracker mechanism. PSE's approved mechanism for the first true-up and prudency review was postponed until its pending 2026 rate proceeding is concluded.

Assessment

The CEIP tracker does not support utility cost control objectives. By providing annual dollar-for-dollar recovery of implementation costs outside of base rates, the mechanism reduces incentives for utilities to manage costs efficiently and minimizes regulatory lag that would otherwise encourage cost discipline in CETA implementation activities.

When initially authorized, the tracker served an important purpose because utilities lacked historical experience with CEIP development and implementation. The mechanism reduced uncertainty associated with the implementation of a major new statutory framework.

That rationale has weakened over time. Utilities have now completed multiple CEIP cycles and possess sufficient historical data to forecast CEIP costs with reasonable accuracy. Activities such as public engagement, data collection, reporting, and compliance management have become recurring business functions rather than novel initiatives.

Although the tracker improves transparency and facilitates annual review of spending, these benefits are outweighed by reduced cost containment incentives and additional administrative burden.

Issues for Attention

The Commission should ensure that elimination of the tracker does not unintentionally affect funding for important programs such as Avista's Named Communities Investment Funds.

Additionally, intervening parties in rate cases have identified transparency benefits associated with annual reporting and public review of CEIP-related expenditures. Alternative mechanisms, such as annual reporting requirements or metrics, may be necessary to preserve accountability while eliminating annual cost recovery adjustments.

Recommended Action

Eliminate the CEIP tracker and incorporate ongoing implementation costs into base rates.[42]

If continued oversight is necessary, maintain annual reporting requirements separate from cost recovery (*e.g.,* to ensure the Named Communities Investment Funds are not negatively impacted). The Commission could also consider targeted deferral authority requested by utilities for unique or extraordinary expenditures that cannot reasonably be forecasted.

Colstrip Adjustment Tracker

[Avista, PSE]

[42] This recommendation does not include statutorily authorized deferrals for major projects under RCW 80.28.410.

Description

The Colstrip Adjustment Tracker removes costs associated with the Colstrip generating facility from customer rates and provides recovery of ongoing **decommissioning and remediation costs**.

Following coal plant retirement requirements on January 1, 2026, the tracker now primarily serves as a mechanism to update and reconcile remaining decommissioning obligations.

Assessment

The tracker is largely neutral with respect to cost control. Decommissioning and remediation obligations are mandated by local, state, and federal laws to safely dismantle assets, clean up environmental damage, and restore sites to protect public health and safety.

The mechanism provides transparency regarding decommissioning liabilities and allows rates to reflect updated cost information on a timely basis. Customers benefit from regular review of obligations that may evolve over time.

Issues for Attention

The principal value of the mechanism is transparency rather than incentive design. Continued monitoring of decommissioning obligations and potential offsets, including production tax credits, remains important.

Recommended Action

Maintain the tracker.

Special Rate Adjustment – Mist Recall

[NW Natural]

Description

Northwest Natural's Mist Recall mechanism allows periodic adjustments associated with utilization of stored gas resources at the utility-owned Mist storage facility. The mechanism is intended to provide lower-cost gas supply options during periods of high market prices and peak demand.

Assessment

The mechanism generally supports cost control because utilization of stored gas can reduce reliance on higher-cost market purchases. By lowering commodity procurement costs, the mechanism can reduce future PGA adjustments and overall customer costs. Unlike many trackers, the mechanism incorporates costs directly into rates and avoids accumulation of carrying costs.

Issues for Attention

Greater transparency regarding utility decision-making would improve both the Commission's and interested parties' understanding of when storage resources are utilized and the resulting customer benefits.

Recommended Action

Maintain the mechanism.

The Commission should consider requiring the utility to provide additional narrative explanations comparing storage utilization decisions with contemporaneous market alternatives with adjustment filings. This comparison supports transparency in utility operations and can compare Mist recall gas costs against hub prices to show whether customers actually benefited.

Tacoma Liquified Natural Gas (LNG) Tracker

[PSE]

Description

The Tacoma LNG tracker provides annual recovery of costs associated with construction, operation, and maintenance of the regulated portion of the **Tacoma LNG facility**.

Assessment

The tracker weakens cost containment incentives because it provides annual recovery of costs outside of traditional rate proceedings. Like many cost recovery trackers, it reduces regulatory lag and limits utility exposure to cost management risks.

However, the mechanism also provides a less complicated review and evaluation process for the regulated portion of the LNG-related expenditures and its operational performance. Because the facility is relatively new and significant costs remain associated with deferred

balances, it is premature to reach definitive conclusions regarding long-term effectiveness.

Issues for Attention

Future review should determine whether continued tracker treatment of LNG costs remains necessary once the facility reaches operational maturity.

Recommended Action

Maintain the tracker in the near term. Reevaluate the tracker in the next general rate case.

Transportation Electrification Plan Tracker

[PSE]

Description

PSE's Transportation Electrification Plan tracker provides recovery of capital investments, **depreciation**, and operating expenses associated with the utility's **Transportation Electrification Plan** (TEP) approved by the Commission.

Assessment

The tracker generally does not support cost containment objectives. By providing annual cost recovery outside of base rates, the mechanism reduces incentives for efficient program administration and cost management. However, the statute promoting utility investment in transportation electrification infrastructure limits the rate impact of transportation electrification expenditures to one-quarter of one percent (0.25%) of total annual retail revenue requirement.

Initially, a separate **tariff schedule** and associated tracker ensured that only customers participating in utility electric vehicle (EV) programs incurred the cost of the program. EV technology adoption has been growing, especially within PSE's service territory, and is quickly approaching a turning point where the benefits of the TEPs inure to the broader society. Further, the annual adjustments have generally been modest and do not appear necessary to support continued program implementation.

Issues for Attention

The Commission should consider whether continued allocation of costs exclusively to participating customers remains appropriate as transportation electrification produces broader system benefits.

PSE's ongoing transition toward **Integrated System Planning** may also provide additional opportunities to incorporate transportation electrification investments into broader utility planning processes.

Recommended Action

Eliminate the tracker at the conclusion of the current TEP cycle (end of 2026) or the next available rate proceeding.

Recover ongoing program costs through base rates while maintaining necessary reporting and oversight requirements.

Cost Recovery Mechanism – Accelerated Pipeline Replacement

[Cascade]

Description

Cascade Natural Gas' Cost Recovery Mechanism provides recovery of costs associated with accelerated replacement of pipeline facilities presenting elevated safety risks.[43]

Assessment

The mechanism weakens cost containment incentives because it provides annual recovery outside general rate case proceedings, reducing the incentive for efficient resource administration and cost management.

At the same time, the mechanism supports important public safety objectives and has contributed to the replacement of higher-risk infrastructure. The challenge is balancing safety priorities with incentives for efficient capital spending.

However, it appears that the most recent annual adjustment under this tracker was completed in 2024.

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[43] PSE previously had a similar tracker, but their work has concluded as was need for the tracker.

Issues for Attention

The Commission should continue evaluating whether annual recovery remains necessary or whether infrastructure replacement costs can be incorporated into future base rates without compromising safety objectives.

Recommended Action

Eliminate the tariff schedule if Cascade's high-risk pipe replacement work has concluded. Otherwise, the Commission should require Cascade to justify the continued tracker treatment if additional work under their plan remains outstanding.

Maintain the Commission's emphasis on safety while evaluating opportunities to simplify cost recovery mechanisms and reduce administrative burden.

Low-Income Bill Assistance Programs

[All]

Description

Washington utilities use a variety of low-income assistance mechanisms to recover costs associated with **Bill Discount Rate programs**, **arrearage management programs**, grants, and related customer assistance initiatives. These mechanisms generally operate through annual true-up adjustments, deferrals, or dedicated tariff schedules that recover program costs from customers not participating in the assistance programs.

The purpose of the customer-funded programs is to reduce **energy burden**, prevent service disconnections, and support achievement of the statutory energy assistance requirements established under CETA.[44] These programs are distinct from federally funded assistance programs such as **Low Income Home Energy Assistance Program** (LIHEAP) and utility-sponsored donation programs.

Assessment

The low-income assistance mechanisms support the broader objective of utility cost control and affordability. Although the mechanisms increase costs for non-participating customers, they help reduce uncollectible balances, collection expenses, service

[44] RCW 19.405.120.

disconnections, and bad debt expense that would otherwise be recovered from all customers through rates.

The programs have become increasingly important as utilities work toward statutory energy burden reduction targets and seek to ensure that the benefits of the clean energy transition are broadly accessible. By lowering customer arrearages and improving bill payment performance, these programs create system-wide benefits that extend beyond participating customers.

The trackers also provide accountability by ensuring that funds collected for low-income assistance are used for their intended purpose and are not redirected toward unrelated utility expenditures.

However, these mechanisms do not directly incentivize utility operational efficiency because costs are generally recovered outside of base rates. Additionally, the programs create cost shifts between customer groups, which raises equity concerns for customers who may experience financial hardship that either have not applied or miss qualifying for assistance by a slim margin.

Issues for Attention

The Commission should evaluate low-income assistance programs as a unified portfolio rather than as individual tariff schedules. The interaction between Bill Discount Rate programs, arrearage management plans, CEIPs, Customer Benefit Indicators, and statutory energy assistance requirements suggests that a holistic review would provide a more complete understanding of program effectiveness.

The Commission's pending policy guidance regarding interpretation of the five-percent funding threshold established under RCW 80.28.425 may significantly affect future program design and funding levels.

The timing of annual true-up adjustments should also be considered because several mechanisms become effective during periods of high customer energy consumption. Rate adjustments that occur during months of high energy usage can disproportionately impact low-income customers not currently participating in utility assistance programs, which is the customer subgroup that these programs are designed to assist.

Recommended Action

Maintain the existing low-income assistance mechanisms.

The Commission should continue evaluating the overall structure of low-income assistance programs through future policy proceedings and affordability metrics. For administrative efficiency, utilities should consider consolidating related low-income annual filings where practical.[45]

The Commission should also evaluate whether annual adjustment effective dates can be shifted to shoulder seasons to reduce customer bill impacts during periods of peak energy usage.

For Cascade Natural Gas, the Commission should consider eliminating carrying costs associated with annual program deferrals or modifying the mechanism to align more closely with recovery structures used by other regulated utilities.

Climate Commitment Act Cost Recovery Mechanisms

[Avista, Cascade, NW Natural]

Description

Washington utilities recover certain costs and benefits associated with compliance with the Climate Commitment Act (CCA) through various tariff schedules, adjustment mechanisms, and existing fuel and power cost recovery mechanisms. The mechanisms reflect **allowance costs**, **no-cost allowance allocations**, **consignment revenues**, and other compliance-related expenses associated with the state's cap-and-invest program.

Because the Department of Ecology administers the program while the Commission regulates utility cost recovery, CCA implementation and the associated regulatory processes involve significant coordination between multiple agencies.

Assessment

The mechanisms are largely neutral with respect to utility cost control at the present time. The primary purpose of these mechanisms is compliance with statutory greenhouse gas reduction requirements rather than the creation of utility efficiency incentives. The current combined CCA and PGA filings are either significantly mitigating or eliminating (in some cases resulting in a refund) the rate increase that would have been experienced with just the annual PGA adjustments. However, given that the number of no-cost allowances

[45] PSE in more recent years has multiple annual low-income program filings.

provided to utilities will decrease over time, that trend is expected to reverse to meet the current compliance timelines. Additionally, customers connected to the gas system after July 25, 2021 (except low-income) are not provided with the CCA bill credits per the statute.

The mechanisms support state climate policy objectives by ensuring utilities can recover prudently incurred compliance costs while also providing increased visibility for the complex treatment of allowance revenues and program expenditures.

At present, substantial uncertainty remains regarding future allowance prices, market design, potential **market linkage**, and long-term compliance obligations. As a result, maintaining flexibility and transparency is more important than establishing new cost-control incentives within the recovery mechanisms themselves.

Issues for Attention

The interaction between CCA recovery mechanisms and existing fuel and power cost adjustment mechanisms deserves continued attention because many compliance-related costs flow through existing trackers rather than dedicated CCA schedules.

The Commission should continue evaluating whether utilities are maximizing customer benefits associated with no-cost allowance revenues and consignment auction proceeds. These proceeds can either be returned to eligible customers through bill credits or used to support programs such as weatherization, decarbonization, conservation, and efficiency services.[46]

Future program modifications by the Department of Ecology, potential market linkage decisions, and evolving compliance obligations may necessitate additional Commission review.

Recommended Action

Maintain existing CCA recovery mechanisms.

The Commission should continue developing guidance regarding transparency, accounting treatment, and presentation of CCA-related costs and benefits. Utilities should be required to demonstrate that customer benefits associated with no-cost allowances

[46] *See* RCW 70A.65.120(3)(b).

and allowance revenues are maximized over the long term (*i.e.*, immediate bill credits versus program support) while considering bill affordability concerns.

The Commission should also consider the timing of CCA-related rate changes in conjunction with other annual rate adjustments to minimize cumulative customer bill impacts.

Environmental Remediation Mechanism

[NW Natural]

Description

Northwest Natural's Environmental Remediation Mechanism provides recovery of prudently incurred **environmental remediation** costs associated with the former Gasco manufacturing site. Recovery is offset by insurance proceeds and is subject to annual prudence review.

The mechanism includes customer protections that limit annual rate increases and restrict recovery of financing costs associated with deferred balances.

Assessment

The mechanism generally supports cost control objectives because it ensures customers pay only for prudently incurred remediation costs while recognizing substantial offsets from insurance recoveries.

The structure includes several customer protections that reduce long-term bill impacts, including annual caps on rate increases and limitations on carrying cost accrual. Historical adjustments have remained relatively modest, reducing customer exposure to significant annual rate volatility.

Unlike broader cost recovery mechanisms that may weaken incentives for efficiency, this mechanism addresses a discrete environmental liability and therefore does not materially affect utility operational decision-making.

Issues for Attention

The principal issue associated with the mechanism relates to timing rather than structure. Annual adjustments occur concurrently with PGA filings, which can compound customer bill impacts during the beginning of the heating season.

Continued monitoring of remediation costs, insurance recoveries, and remaining liability exposure remains appropriate.

Recommended Action

Maintain the mechanism.

The Commission should consider shifting the effective date to occur after the winter heating season to reduce cumulative customer bill impacts associated with simultaneous annual adjustments.

Wildfire Prevention Tracker

[PSE]

Description

Puget Sound Energy's Wildfire Prevention Tracker provides recovery of capital expenditures, operating expenses, and insurance costs associated with the implementation of the company's **Wildfire Mitigation Plan**.

The tracker was established to facilitate timely recovery of wildfire-related investments and improve utility preparedness in response to increasing wildfire risks.

Assessment

The tracker does not support utility cost control objectives. By providing annual recovery of both capital and operating expenses outside of general rate case proceedings, the mechanism reduces incentives for cost containment and limits regulatory lag that would otherwise encourage efficiency.

Unlike some performance-based regulatory tools, the tracker is not currently tied to cost efficiency metrics, performance targets, or measurable outcomes. As a result, customers bear much of the financial risk while receiving limited assurance that expenditures are optimized.

The tracker does, however, support important public safety and reliability objectives. Wildfire mitigation has become an increasingly significant utility responsibility, and timely investment may reduce future costs associated with catastrophic wildfire events.

Issues for Attention

The Commission should evaluate differences in regulatory treatment among utilities. PSE currently utilizes a dedicated tracker for the entirety of program costs while other utilities rely on alternative recovery mechanisms or traditional ratemaking approaches. [47]

The Commission has also identified concerns regarding documentation and contemporaneous analysis supporting certain deferred insurance costs. [48] Future recovery requests should continue to receive heightened scrutiny.

As utilities gain additional experience implementing wildfire mitigation plans, the Commission should consider whether performance metrics or efficiency measures should accompany future cost recovery requests.

Recommended Action

Modify the mechanism. Restructure as a balancing account with capital investments incorporated back into base rates. The utility could retain needed flexibility through the existing portfolio review of provisional plant as currently employed in MYRPs.

Regardless, PSE should provide enhanced reporting with their annual cost recovery filing demonstrating the effectiveness of expenditures, measurable risk reduction achieved, and efforts undertaken to control program costs.

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[47] Refer to Avista's wildfire balancing account. PacifiCorp does not have a mechanism outside of base rates.

[48] During the Open Meeting held on March 12, 2026, the Commission expressed concern regarding the lack of decision-making documentation provided with the Company's insurance coverage levels and expenses. The Commission required the Company to provide such documentation and deemed the insurance portion of the request as subject to refund pending that documentation. *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy,* Granting Petition to Defer Accounting Treatment of PSE's Wildfire Insurance Costs, Docket UE-250931, Order 01 at ¶ 28 (Mar. 13, 2026). Open Meeting Recording website.

Residential Rate Mitigation Mechanism

[NW Natural]

Description

The Residential Rate Mitigation Mechanism was authorized to moderate the impact of significant rate increases on residential customers resulting from NW Natural's 2020 general rate case[49] with a concurrent PGA rate increase to avoid **rate shock**. The mechanism deferred certain PGA costs for later recovery, thereby smoothing recovery of approved costs over time rather than a singular large rate adjustment.

Assessment

The mechanism supports affordability objectives by reducing rate shock and improving bill stability for residential customers. The mechanism can be particularly valuable during periods of rapid inflation, significant capital investment, or implementation of major public policy initiatives.

However, the mechanism does not improve utility cost control. Cost recovery is generally delayed rather than reduced, and deferred balances may accumulate carrying costs that increase customer financial obligations. The mechanism therefore addresses timing of recovery rather than underlying cost drivers.

Issues for Attention

The Commission should evaluate the cumulative impact of deferred balances and associated carrying costs across the industry. While rate mitigation may improve near-term affordability, excessive reliance on deferrals can shift costs to future customers and obscure the true cost of service. Further, a delayed recovery on one cost can then be "stacked" (also referred to as pancaking) with future rate adjustments.

Recommended Action

Maintain the mechanism as a limited affordability tool.

The Commission should use caution with any future rate mitigation proposals. Delaying recovery of prudently incurred costs can result in customers paying more in the long run with no additional benefit.

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[49] NW Natural's 2020 GRC Docket UG-200994.

Participatory Funding Mechanisms

[All]

Description

Participatory funding refers to state-mandated financial programs that reimburse **community-based organizations**, tribes, and **consumer advocates** for participating in regulatory proceedings. Participatory funding mechanisms can support broader engagement in utility planning, policy development, and regulatory proceedings. Providing such financial resources to community-based organizations, tribes, consumer advocates, and other interested parties provides diverse perspectives to the benefit of both the Commission and the customers represented by those groups. The funding level for this mechanism is currently determined by a multi-party agreement in the Commission's Participatory Funding Policy Statement docket.[50]

Assessment

The mechanisms promote transparency, equity, and procedural fairness by reducing barriers to participation. Enhanced participation can improve regulatory outcomes and increase confidence in Commission decision-making.

These administrative costs are generally modest compared to overall utility revenue requirements.

Issues for Attention

The Commission should continue evaluating program effectiveness and ensure funding is producing measurable improvements in participation and engagement rather than creating unnecessary administrative complexity. This evaluation is pending in the current policy statement docket.

The current carrying costs are authorized at the **FERC rate**. This rate may not be appropriate as it does not represent the individual utility's financial risk or financing costs.

Recommended Action

Modify.

[50] Docket U-210595.

Revise the authorized carrying cost at each utility's after-tax cost of debt.

Conservation, Energy Efficiency, and Demand Response Riders

[All – Conservation]

Description

These mechanisms provide recovery of utility expenditures associated with conservation programs, energy efficiency investments, and demand response initiatives approved by the Commission.[51] Utilities must file biennial conservation plans with an annual update.[52] The annual cost recovery filings must be submitted no later than June 1.[53]

Assessment

Unlike many cost recovery trackers, these mechanisms directly support least-cost planning objectives and often generate net benefits for customers through reduced system costs, avoided infrastructure investments, and lower energy consumption.

Demand response programs also improve system flexibility and reliability while helping utilities manage peak demand growth. These benefits are increasingly important as electrification expands and utilities seek cost-effective alternatives to traditional infrastructure investment.

Further, these mechanisms are currently required by rule as permitted by statute. However, annual recovery outside of base rates may reduce cost containment incentives and may increase administrative burden through separate filings and true-up proceedings.

Issues for Attention

The Commission should continue evaluating cost-effectiveness standards and ensure program expenditures produce measurable customer benefits. However, the cost recovery filings do not enumerate valuable information as the Commission considers the program costs.

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[51] The PacifiCorp conservation mechanism is called the System Benefit Charge.

[52] WAC 480-109-120.

[53] WAC 480-109-130 and RCW 19.285.050(2).

Reporting appears inconsistent across the utilities. Both the presentation of data and **cost-effectiveness tests** applied are different. This can create challenges in program comparisons.

The interaction between these riders, Integrated Resource Planning, Integrated System Plans, Clean Energy Implementation Plans, and future PBR metrics should also be monitored.

Recommended Action

Maintain the riders.

Continue requiring robust cost-effectiveness analysis and program evaluation. This includes strengthening the connection between the required annual update to the Biennial Conservation Plan and the cost recovery filings. We recommend the Commission require the utilities to provide narrative in the cost recovery filing indicating the benefits achieved associated with the filing. Additionally, we recommend utilities disclose the percentage of funding used for administration of the program.

Administrative efficiencies may also be gained by moving the true-up to coincide with the end of the biennial program period rather than annually. This recommendation would require a **rulemaking** to update the WAC language.

A standardized reporting tool (template) is also recommended with further investigation into which tests are most appropriate and expected.

Property Tax Tracker

[PSE]

Description

The Property Tax tracker was created to pass through these specific expenses to customers on a dollar-for-dollar basis. The structure includes both a forecast for the subsequent year and a true-up for the previous period in the annual filing.

Assessment

Property taxes are largely outside utility management control and can fluctuate significantly due to reassessments, changing property values, and local government tax decisions.

The tracker improves regulatory accuracy by aligning rates with actual tax obligations and reducing regulatory lag. Because property taxes are externally determined, the mechanism has limited impact on utility operational decision-making.

However, annual pass-through treatment also removes incentives for utilities to challenge assessments or seek reductions where appropriate. Further, the small annual adjustments may indicate that these costs are not volatile, and the utility can adequately project expenses year-to-year.

While the mechanism is neutral for cost control, it is negative for administrative efficiency.

Issues for Attention

PSE is the only utility with this tracker and is not a necessity. The annual adjustments have been minimal over the previous five years.

Recommended Action

Eliminate the tracker.

If a material impact occurs in the future, the utility may file a **petition** for a one-time deferral.

Adjustment for Property Sales

[NW Natural]

Description

This mechanism was created to pass back the proceeds from property sales to customers.

Assessment

The mechanism promotes fairness by ensuring customers appropriately share in benefits associated with property transactions when required by Commission precedent and regulatory accounting treatment.

The mechanism is generally neutral regarding utility cost control because property sales occur infrequently and are subject to Commission oversight.

Issues for Attention

Despite the positive outcome for customers the mechanism is negative for administrative efficiency. Nothing precludes the utility from requesting deferrals for the gain or loss on sales.

Recommended Action

Eliminate the mechanism.

Insurance Expense Balancing Account

[Avista]

Description

The Insurance Expense Balancing Account reconciles differences between forecasted insurance costs embedded in base rates and actual insurance expenses incurred by the utility. In 2021, the Commission authorized the balancing account for the term of the 10-year life of Avista's Wildfire Resiliency Plan.[54]

Assessment

The mechanism reduces financial risk associated with increasingly volatile insurance markets. In recent years, utilities have experienced significant premium increases driven by wildfire risk, severe weather events, and changing market conditions.

While the balancing account improves financial stability, it weakens cost containment incentives because utilities receive recovery of actual insurance costs regardless of forecasting accuracy or management decisions.

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[54] *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-200900, UG-200901, UE-200894 (*Consolidated*), Order 08/05 at ¶¶ 254-259 (Sept. 27, 2021). In that order, the Commission also required the Company to propose metrics to ensure the effectiveness of wildfire expenses. The metric approved in the 2022 GRC (UE-220053 and UG-220054) continues to be reported [Wildfire avoidance – number of utility-caused wildfires, ignition events, and risk events]. Additional performance measures are contained in Avista's Wildfire Resiliency (mitigation) Plan in Docket UE-240836.

Over the last three years, the annual adjustments across both electric and natural gas operations averaged an increase in revenue requirement of 0.19 percent. This may indicate that either the volatility is normalizing or the company is adequately able to forecast the expenses. However, the MYRP periods have been relatively short (two years). It is unknown if a longer MYRP term would alter the ability to maintain accurate forecasting.

Issues for Attention

The Commission should continue examining utility procurement practices and ensure insurance purchasing decisions are prudent and cost-effective. These costs are significantly outside of the individual utility's control.

Recommended Action

Maintain the mechanism.

Re-evaluate following the conclusion of the MYRP term from the pending rate case if a longer plan period is authorized.

Wildfire Balancing Account

[Avista]

Description

The Wildfire Balancing Account reconciles differences between forecasted costs embedded in base rates and actual wildfire-related costs, including **mitigation activities**, **vegetation management**, and other expenses incurred in the Company's Wildfire Mitigation Plan.

Assessment

The mechanism supports important public safety and reliability objectives. Wildfire risks continue to increase throughout the western United States, and utilities require flexibility to respond to changing conditions. Particularly, Avista's service territory covers communities and land designated as low (urban areas) to high risk (rural areas that may include **wildland-urban interfaces**, also known as WUIs).

Since 2021, the Commission has held informational meetings (recessed open meetings) to hear lessons learned from the previous wildfire season and receive updates on utility

operational changes in response to changing conditions and gained experiences.[55] During the 2025 legislative session, HB 1522 was passed, which required the Commission to take action on electric utility wildfire mitigation plans. This creates an additional level of scrutiny of the plans as the bill also requires a public workshop and hearing.

However, full balancing account treatment weakens cost containment incentives because costs are largely passed through to customers.

Issues for Attention

The Commission should carefully evaluate whether balancing account treatment remains necessary as utilities develop more mature wildfire mitigation programs and forecasting capabilities. Policy recommends this evaluation during the next MYRP filed by the utility.

The interaction between wildfire balancing accounts, dedicated wildfire adjustment mechanisms, and future performance metrics warrants further review. This includes an analysis of the magnitude of the annual adjustment.

Recommended Action

Maintain the mechanism.

Similar to Avista's Insurance Balancing Account, we recommend re-evaluating the mechanism following the conclusion of the MYRP term from the pending rate case.[56] That case includes a proposal for a period extending beyond two years that may provide better evaluation of the ability for accurate long-term forecasting.

Bonneville Power Administration Residential Exchange Program

[Avista, PacifiCorp, PSE]

Description

The Bonneville Power Administration Residential Exchange Program (BPA REP) passes benefits associated with the federal Columbia River power system through to qualifying customers.[57]

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[55] These meetings include information from all three regulated electric utilities.

[56] This period may be close to the original approval for a 10-year mechanism.

[57] See BPA's Residential Exchange Program website.

Assessment

The mechanism functions primarily as a flow-through accounting adjustment and has little-to-no impact on utility incentives or cost control. The primary purpose is ensuring customers receive benefits authorized under federal law.

The mechanism improves affordability by providing direct customer credits and does not create significant administrative burden.

Issues for Attention

Future changes to BPA policy or federal law may affect program benefits and should continue to be monitored.

Recommended Action

Maintain the mechanism.

Continue annual reconciliation and transparent reporting of customer benefits.

Other Considerations

Accounting Deferrals

Description

Accounting deferrals allow utilities to record extraordinary, unforeseen, or timing-related costs and revenues for future recovery or refund rather than immediately recognizing them in rates.

Assessment

Interested parties that regularly participate in Commission proceedings have expressed concerns over the use of deferrals. Opinions range from eliminating the use of deferrals completely to establishing more stringent parameters, including a **materiality threshold**.

We believe that deferrals provide important regulatory flexibility and can reduce the need for frequent rate proceedings when unusual events occur. They are particularly useful for **pilot programs**, supporting limited but important public policies, responding to catastrophic events, or recovering costs that cannot reasonably be forecast.

However, widespread reliance on deferrals can undermine cost containment incentives, reduce transparency, and create substantial deferred balances that ultimately increase customer costs through both the costs themselves and authorized carrying costs.

Additionally, as MYRP periods become longer, deferrals may incur carrying costs for significantly extended periods. This situation would increase the final bill impacts to customers for the actual utility expense incurred possibly three to four years earlier.

Current Commission precedent is that deferral treatment is limited to extraordinary circumstances including those: (1) beyond the utility's control; or (2) having a material impact on the company's finances.[58]

As part of the work in this assessment, we gathered five years of historical deferral activity (deferral data).[59]

Commission Staff previously provided an example using the MYRP statutory earnings test threshold (0.05%).[60] We applied that standard to the deferral data and found that 16 of the 72 deferrals fell below that threshold. Applying a threshold twice Staff's example (0.10%) would only eliminate two additional deferrals.

However, it is important to consider which deferrals would have been eliminated. The table below provides the information about the eliminated deferrals and other reasons why the deferral may have remained appropriate.

[58] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.,* Dockets UE-050684 and UE-050412, Order 04, 123, ¶370.

[59] *See* Appendix B.

[60] Citation. 0.05 percent equates to 5 basis points of rate of return. For example, if a utility's rate of return is authorized at 7.5 percent, then a deferral threshold is not met until the expense reduced the rate of return to 7.45 percent. Refer to Appendix B – Tab "Deferral Materiality Review" for the 0.05 and 0.10 percent revenue requirement impacts of the respective thresholds.

Table 6: Deferrals Theoretically Eliminated by Thresholds

Deferral	Companies Impacted	Eliminating Threshold	Other Considerations
Participatory Funding	Avista (E/NG) Cascade PacifiCorp PSE (E/NG)	0.05%	Public Policy (equity)
EV Pilot	PacifiCorp	0.10%	Pilot (emerging technologies)
Cost of Import Tariffs	Avista (gas) Cascade PSE (gas)	0.05%	Beyond utilities' control
Arrearage Management Plan	NW Natural	0.05%	Public Policy (equity)
Industrial Insurance Energy Efficiency Audit Costs (non-residential customers)	NW Natural	0.05%	
UTC Regulatory Fee	PacifiCorp NW Natural	0.05% 0.10%	Beyond utilities' control
Montana Riverbed Lease Agreement	Avista	0.05%	
DR Programs	PSE (electric)	0.05%	Public Policy (conservation)
CEIP Implementation Costs	PSE (electric)	0.05%	Public Policy (costs for initial mandate)
DR PPAs – deferred return	PSE (electric)	0.05%	Public Policy (conservation)

It is important to remember that the mere approval of a petition for deferral does not guarantee recovery. Further, a threshold greater than 0.10 percent could create unintended consequences such as a negative impact on financial credit metrics that may result in increased cost of capital (*i.e.,* customers paying higher utility financing costs).

Additionally, utilities could also be incentivized to propose shorter rate plans undermining the cost control benefits of longer MYRPs.

Finally, many requests for deferred accounting treatment lacked information about the expected magnitude of the anticipated expense. We understand that deferral requests for nascent public policy or legislative mandates may be extremely difficult to surmise at the time of the filing. However, there were other instances where an estimated deferral amount should have been reasonably known by the utility.

Issues for Attention

The Commission should monitor the cumulative magnitude of deferred balances and avoid routine use of deferrals for costs that have become predictable business activities.

The distinction between extraordinary and recurring costs should remain a central consideration in approving future deferral requests.

Recommended Action

Maintain deferral authority as an important regulatory tool.

We recommend the Commission require utilities to provide the best estimate of the expected deferral amount in the initial filing. If an estimate is not reasonably known at the initial filing, the utility should communicate those reasons. This is not intended to impose arbitrary future limitations on the amount eligible for recovery. Rather, this provides the Commission and interested parties with a better understanding of the magnitude of the expense in response to and consideration of the request.

We recommend requiring utilities to provide details regarding outstanding deferral information with the annual Commission Basis Report.[61]

We do not recommend that the Commission set a strict materiality threshold as a matter of policy. The evaluation of the deferral data did not clearly identify that a **bright-line threshold** would serve the public interest. Additionally, such a threshold would unnecessarily reduce the flexibility of this tool. However, we believe the Commission can re-evaluate the deferral against the same criteria at the time recovery is requested.

Finally, where deferrals may be utilized as a tracker tool, ongoing costs should be periodically evaluated to determine whether those costs should instead be incorporated into base rates.

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[61] Similar to Appendix B: Tab "Deferrals per Company."

Tracker Mechanism Principles

The regulatory concept of trackers is not a new phenomenon. However, with the implementation of MYRPs and proliferation of cost trackers as a routine cost recovery mechanism for many utilities, there are heightened concerns about the circumstances in which a tracker is appropriate.[62] Indeed, this paper highlights several existing mechanisms that may require the Commission to revisit what parameters should be considered for consistent application of these regulatory mechanisms.

In 2009, the National Regulatory Research Institute (NRRI)[63] held a teleconference regarding cost trackers that remains relevant today. During this teleconference a set of regulatory rationales for cost trackers were discussed.[64] These included the existence of extraordinary circumstances and severe financial consequences.

In describing extraordinary circumstances, Costello included three components: (1) the costs are largely outside the utility's control; (2) the costs are unpredictable and volatile; and (3) the costs are substantial and recurring.[65] These components are commonly accepted by regulatory commissions but the practice of requiring all three conditions to authorize a tracker is inconsistent.

Across jurisdictions, there is not a single, commonly accepted definition for these parameters; rather, an evaluation of extraordinary circumstances and the potential use of trackers has been context-specific.

During the last few years, there have been anecdotal stories (both in Washington and nationally) that utilities receive more than 50 percent of their revenue through trackers. At least two other commissions are investigating this concern. In Massachusetts,

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[62] *See* Wilson, G., Whited, M., Havumaki, B., Lane, C., & Goldenberg, C. (2025, November 3). *Fixing Multiyear Rate Plans*. RMI website (last visited June 6, 2026).

[63] NRRI was absorbed directly into NARUC as of July 1, 2022.

[64] *See* Costello, K. (2009). The Two Sides of Cost Trackers: Why Regulators Must Consider Both. Minnesota Public Utilities Commission website (last visited June 9, 2026).

[65] Costello, K. (2009). The Two Sides of Cost Trackers: Why Regulators Must Consider Both at 7-8. Minnesota Public Utilities Commission website (last visited June 9, 2026). *Note*: The distinguishing difference in the principles between trackers and a deferral is the recurring versus one-time expense.

reconciliation mechanisms (*i.e.,* cost trackers) accounted for 39 percent of total electric utility revenues requirements in 2025 and 40 percent of total gas utility revenue requirements.[66] In Virginia, cost trackers represented roughly 30 percent of the average Dominion Energy residential customer's bill in 2024, and 28 percent for the average residential customer of Appalachian Power Company.[67]

In this docket, the Commission adopted a metric to provide transparency and enable us to monitor these trends. An initial review of the submitted metric data indicates the proportion of revenues recovered through trackers varies across fuel types. Electric operations range from 11 to 22 percent of revenues recovered through trackers, with natural gas operations accounting for 44 to 64 percent, primarily due to the PGA mechanisms.[68] When the PGA mechanism is removed, those results range from 10 to 22 percent, similar to electric operations.[69]

We provide the above analysis for context in continuing the discussion on trackers, their impacts, and the consideration of circumstances where trackers may be appropriate. Policy Staff believe there are valid reasons for the continued use of discrete trackers but encourage broader discussion before providing specific recommendations. The following provides a basis for those future discussions.

In the PSE 2024 rate proceeding, Regulatory Staff proposed three criteria when considering cost trackers. These were: (1) does the tracker advance a public policy goal; (2) does the tracker address potential intergenerational inequities; and (3) does the tracker address a

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[66] Refer to MA DPU Docket 25-200 through its website. We note that Massachusetts is not a vertically integrated state.

[67] Refer to the VA PUC Status Report on its Implementation of the Virginia Electric Utility Regulation Act at pages 4 and 7.

[68] NW Natural Gas did not provide data for this metric as they were not under a MYRP for the 2025 reporting period.

[69] The raw data is available in each utility's 2025 Commission Basis Reports (CBR). Those reports may be accessed through the Commission's website. Avista Electric CBR, Avista Gas CBR, Cascade CBR, PacifiCorp CBR, PSE Electric CBR, and PSE Gas CBR. NW Natural did not file data for this metric. Policy Staff considered schedules for municipal taxes, provisional plant, and voluntary schedules as base rates for the purpose of this analysis.

variance risk that is outside the utility's control and has a substantial impact on the utility's earnings.[70] Commission Staff refers to these criteria as serving the public interest.[71]

Additionally, policy questions were raised by Commission Staff for a tracker to "generate specific public interest benefits that are sufficient to overcome the harmful effects the tracker creates."[72] Such as:

- before authorizing a tracker to eliminate the utility's incentive to cut costs, the Commission should consider whether establishing a performance measure, or PIM, would be a more appropriate solution;[73]
- trackers should be viewed only as a temporary stop-gap measure and not a permanent ratemaking solution;[74] and
- trackers should never fully eliminate the variance risk for utilities and require a risk-sharing mechanism as part of the design.[75]

Other regulatory commissions have formally recognized the need to evaluate both existing trackers and establish parameters for future trackers. However, in our limited research, we were unable to locate any commission that has issued such guidance.[76]

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[70] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy,* Dockets UE-240004 &UG-240005 (*Consolidated*) UE-230810, McGuire, Exh. CRM-1Tr at 35:16-43:22.

[71] Commission Staff also appropriately recognizes that certain trackers may be required by statute and not applicable to such considerations. *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy,* Dockets UE-240004 &UG-240005 (*Consolidated*) UE-230810, McGuire, Exh. CRM-1Tr at 48:11.

[72] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy,* Dockets UE-240004 &UG-240005 (*Consolidated*) UE-230810, McGuire, Exh. CRM-1Tr at 46:5-6.

[73] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy,* Dockets UE-240004 &UG-240005 (*Consolidated*) UE-230810, McGuire, Exh. CRM-1Tr at 46:22-47:1.

[74] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy,* Dockets UE-240004 &UG-240005 (*Consolidated*) UE-230810, McGuire, Exh. CRM-1Tr at 47:11-12. Policy Staff recognizes there may be exceptions, like fuel cost recovery mechanisms.

[75] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy,* Dockets UE-240004 &UG-240005 (*Consolidated*) UE-230810, McGuire, Exh. CRM-1Tr at 52:4-6.

[76] A couple of prominent PBR-forward states have yet to address this issue. For example, Hawaii kept the existing regulatory mechanisms in place during their implementation of PBR (*See* Hawaii Public Utilities Commission Docket No. 2018-0088). Connecticut is current in Phase 2 of their PBR proceeding that addresses regulatory mechanisms such as trackers. However, they have yet to issue any findings or conclude their work (*See* Connecticut Public Utilities Regulatory Authority Docket No. 21-05-15).

We recommend the Commission provide additional guidance regarding trackers within this docket. However, until such guidance is issued, Policy Staff recommend asking six foundational questions when evaluating trackers in advance of that guidance:

1. Is the mechanism allowed or required by law?
2. Is the mechanism well defined?
3. Is the mechanism needed and does it address the problem?
4. Are there any performance standards, tradeoffs, or other reflections of changes of risk?
5. Are there any customer protections?
6. Are there any alternative approaches that are better suited to address the identified problem?

Additionally, we recommend the Commission consider more detailed information regarding proposed tracker characteristics, potential drawbacks, potential benefits, and transparency in its guidance. Provided below are a few examples of the type of questions that may be appropriate.

<u>Tracker Characteristics</u>

- Is it a balancing account (projected amount embedded in rates) or solely recovered through the tracker?
- Does it reconcile over/under-collection?
- What type and level of review and approval is required?

<u>Potential Drawbacks</u>

- Are the categories of eligible cost recovery clearly differentiated from revenues recovered through other mechanisms?
- Does the tracker allow straight pass through of utility expenses?
- Does the tracker reduce cost control incentives?
- Does the tracker exacerbate capital investment bias?

<u>Potential Benefits</u>

- Does the tracker reduce financial risks?
- Does it provide accurate cost recovery?
- Does it support administrative efficiency?
- Does it include cost control incentives?
- Would the utility be materially damaged by loss of tracker recovery?

<u>Transparency</u>

- What percentage of total revenues does this tracker represent?
- How volatile has spending against this cost tracker been over time?
- How does it appear on customer bills?

Further, we recommend three considerations in developing guidance: (1) require a minimum three-month review period to allow staff and other interested parties adequate time to evaluate the annual tracker adjustments; (2) establish a sunset date or periodic reevaluation process to ensure the conditions that existed under the original circumstances remain relevant; and (3) require each subsequent adjustment filing to include detailed justification, both narrative and in workpapers, for the requested rate change in the initial submission.

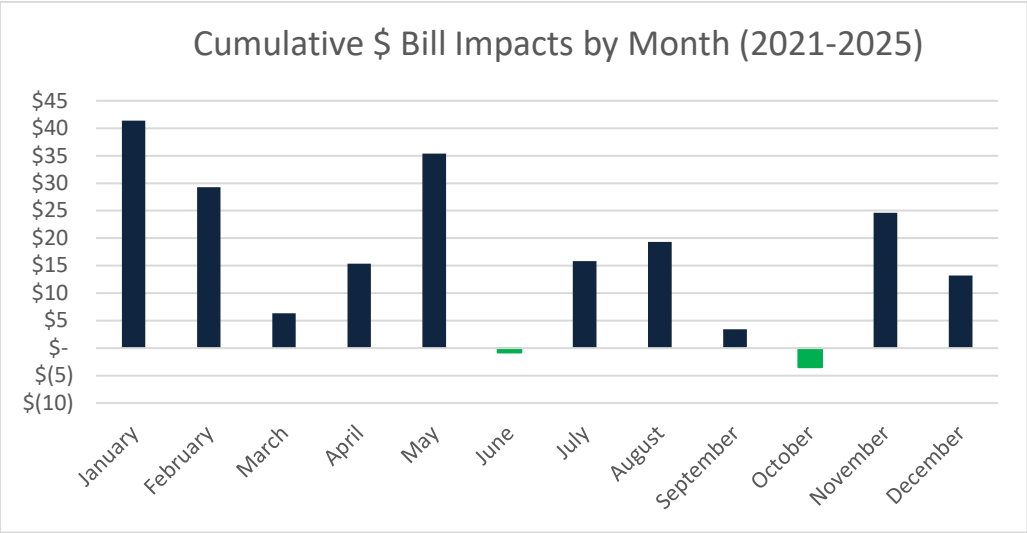
Finally, Policy Staff reviewed both the frequency, financial magnitude, and timing of the regulatory mechanisms discussed in this paper. A significant number of high-impact changes are occurring during high usage periods (*i.e.,* the winter heating season).

Table 7: Cumulative Number of Filing Effective Dates (2021-2025)[77]

MONTH	2021	2022	2023	2024	2025	TOTAL	AVERAGE
JANUARY	3	2	4	8	12	29	5.8
FEBRUARY	1	2	1	0	1	5	1
MARCH	0	0	1	1	1	3	0.6
APRIL	0	1	1	2	2	6	1.2
MAY	6	7	6	11	9	39	7.8
JUNE	0	0	0	1	2	3	0.6
JULY	3	3	1	0	1	8	1.6
AUGUST	3	0	6	5	9	23	4.6
SEPTEMBER	0	1	2	2	1	6	1.2
OCTOBER	10	9	5	6	5	35	7
NOVEMBER	16	16	25	25	22	104	20.8
DECEMBER	0	3	3	0	1	7	1.4

[77] The number of filings and cumulative bill impact charts include the effects of all filings (inclusive of MYRPs).

Figure 5: Cumulative Bill Impact for All Filings and Utilities (in 2025 USD)



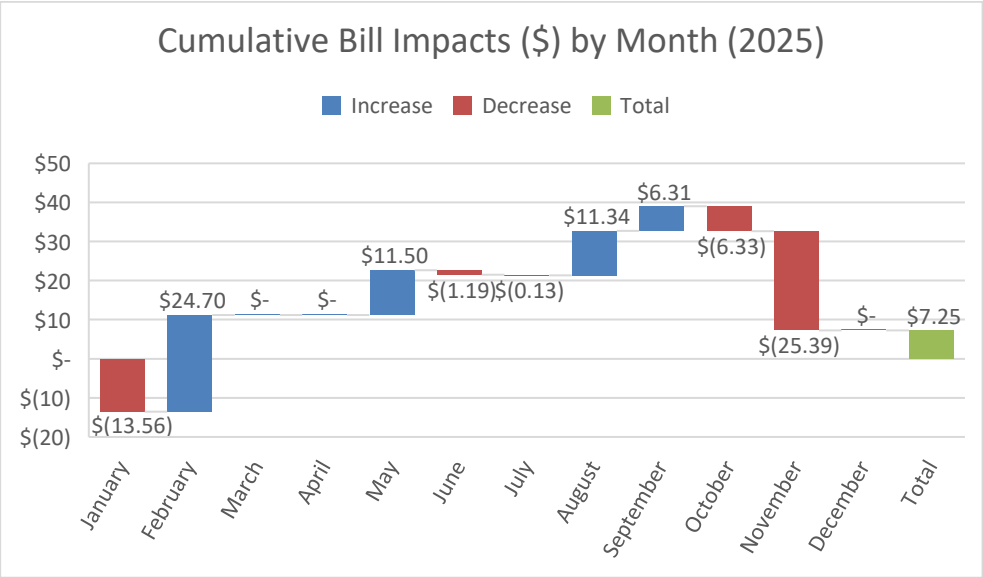
When looking at the data for 2025 by utility (excluding MYRPs) a similar trend appears.

Table 8: Number of Filings with Effective Dates by Month and Utility[78]

MONTH	AVA	CNG	NWNG	PAC	PSE	TOTAL
JANUARY			2		6	8
FEBRUARY				1		1
MARCH						0
APRIL						0
MAY					9	9
JUNE		1				1
JULY	1					1
AUGUST	7			1	1	9
SEPTEMBER				1		1
OCTOBER				1	4	5
NOVEMBER	8	6	6		2	22
DECEMBER						0

[78] Dual-fuel utilities are counted for each filing fuel type. For example, Avista's conservation program is applicable to both electric and natural gas customers and represents two filings for the purpose of this table.

Figure 6: Cumulative Bill Impact for All Utilities (in 2025 USD)[79]



Regardless of the decided outcome of each mechanism, we find reason to reevaluate when, which, and how often utilities change rates for both the benefit of customers and regulatory efficiency. We do not take this recommendation lightly given the significant efforts required by utilities to adjust their business practices. However, Policy Staff believe this one-time effort outweighs the benefits.

Policy Staff provides an illustrative example based on the mechanism recommendations included in this paper. We do not purport to understand all implications or restrictions for the historical timing of the filings. We look for the utilities and interested parties to provide fact-based reasoning to support additional recommendations to the Commission.

The rationale used in developing our example included: (1) avoiding high impact filings during peak cooling and heating season; (2) attempting to pair filings by impact levels to avoid rate shock; (3) consolidating filings by program type; and (4) limiting each utility to no more than four rate changes per year.

[79] The significant decreases are primarily driven by the CCA non-volumetric bill credits. It is important to note that customers gaining service after July 2021 to not receive those credits and therefore they did not experience the effects depicted by the chart.

Figure 7: Illustrative Example of Filing Effective Dates

FEBRUARY		
Mechanism	**Company**	**RS Section**
Conservation	Avista CNG NWNG PAC PSE	Energy Planning
MIST Recall	NWNG	Rates & Tariffs
EDIT	CNG	Rates & Tariffs
Environmental Remediation	NWNG	Rates & Tariffs
Colstrip	Avista PSE	Rates & Tariffs

MAY		
Mechanism	**Company**	**RS Section**
PGA/CCA	Avista CNG NWNG PSE	Rates & Services
Federal Incentive	PSE	Rates & Services
Energy Charge Credit	PSE	Rates & Services
PSE TEP	PSE	Energy Planning

AUGUST		
Mechanism	**Company**	**RS Section**
Decoupling	Avista CNG PAC PSE	Rates & Tariffs
Low Income	Avista CNG NWNG PAC PSE	Rates & Tariffs
Participatory Funding	Avista CNG NWNG PAC PSE	Rates & Tariffs

OCTOBER		
Mechanism	**Company**	**RS Section**
PCAM/ERM	Avista PAC PSE	Rates & Tariffs
BPA REP	Avista PAC PSE	Rates & Tariffs
Avista Insurance	Avista	Rates & Tariffs
Wildfire	Avista PSE	Energy Transformation
PSE LNG	PSE	Rates & Tariffs

COLOR-CODING LEGEND
LOW IMPACT
MEDIUM LOW IMPACT
MEDIUM IMPACT
MEDIUM HIGH IMPACT
HIGH IMPACT

Again, we recommend soliciting all participating parties to provide their perspectives for the appropriate cost tracker parameters. The Commission's guidance may then be included in the next PBR policy statement (anticipated in Quarter 1 of 2027).

Return on Equity

Some participants have expressed that authorized **return on equity** (ROE) should be reassessed in this docket given the implementation of PBR and the reduced business and

financial risks for utilities associated with the existing cost trackers. Policy Staff believe the Commission should evaluate if ROE adjustments are warranted to better match utility risk. However, this matter must be addressed for each utilities' unique circumstances. Therefore, while general discussions may be helpful, each utility's circumstances must be evaluated and determined through a formal record.

Conclusions

A recurring theme throughout this assessment is the importance of balancing customer affordability with utility financial health. Many mechanisms that appropriately reduce utility risk or support public policy objectives also weaken incentives for cost containment when viewed in isolation. Conversely, mechanisms that strengthen efficiency incentives may increase financial risk or reduce flexibility needed to address emerging challenges such as wildfire mitigation, climate adaptation, electrification, and compliance with state energy policy. The Commission's challenge is therefore not to maximize any single objective, but to maintain an appropriate balance among competing public interest considerations.

The recommendations contained in this paper reflect that balanced approach. In general, the assessment favors maintaining mechanisms that continue to provide clear customer benefits, support statutory requirements, or advance important public policy objectives. Where modifications are recommended, they are intended to improve regulatory efficiency, strengthen cost-control incentives, increase transparency, reduce unnecessary rate volatility, or better align utility and customer interests. Several recommendations also seek to simplify the regulatory framework by consolidating mature programs into base rates, standardizing filing practices, aligning adjustment effective dates, and reducing duplicative review processes.

This regulatory assessment demonstrates that Washington's current framework already contains many of the core elements commonly associated with PBR. Multiyear rate plans, revenue decoupling, performance metrics, earnings tests, and targeted adjustment mechanisms collectively provide the Commission with a robust set of regulatory tools to advance reliability, affordability, equity, environmental objectives, and utility financial stability.

The assessment does not support the conclusion that Washington requires a fundamental restructuring of its regulatory framework or abandoning its PBR work. Rather, the findings suggest that the Commission's existing regulatory mechanisms generally achieve their intended purposes and, in many cases, provide customer protections while supporting utility investment and operational needs. At the same time, the cumulative interaction of these mechanisms has increased regulatory complexity, administrative burden, and the frequency of rate adjustments experienced by customers.

The assessment further concludes that Washington should continue following a measured and data-driven approach to PBR. The Commission has already established goals, outcomes, performance metrics, and guiding principles through this docket (U-210590).

Those foundational elements provide an appropriate framework for future development of scorecards, performance targets, and incentive mechanisms. Consistent with national best practices, reported metrics should continue to be evaluated before broader deployment of financial incentives, allowing the Commission to better understand baseline performance, identify trends, and avoid unintended consequences.

Finally, this paper should be viewed as a starting point rather than an endpoint. Utility regulation must continue to evolve alongside changing technologies, customer expectations, environmental requirements, and economic conditions. The recommendations presented here are intended to support continued discussion regarding how Washington can best achieve safe, affordable, reliable, and equitable utility service at the lowest reasonable cost. As additional data becomes available and experience is gained under the current PBR framework, the Commission should periodically revisit the framework and adjust where warranted.

Glossary

These terms were defined by Policy Staff for those readers unfamiliar with regulatory terms and processes to better understand the lay meaning. The definitions do not necessarily reflect Commission-recognized definitions for parties with a deeper understanding of the nuance behind these terms.

Term	Definition
Adjudication	Formal, trial-like legal process used by regulatory agencies to resolve contested cases, such as rate increases, tariff revisions, and compliance disputes. These formal proceedings are governed by the state's Administrative Procedure Act (APA) under RCW 34.05.
Administrative burden	Collective time, effort, and stress people, businesses, and organizations face when navigating or administering rules, procedures, or requirements set by governments or large institutions.
Advanced technologies	Innovative, cutting-edge, or complex technology available – such as artificial intelligence, Internet of Things (IoT), smart grid systems, dynamic line ratings, and advanced power flow controllers, among others.
After-tax cost of debt	The actual cost a company pays on its borrowing, adjusted for the tax savings from interest deductions. Interest payments are tax-deductible; therefore, the actual cost of debt is lower than the stated interest rate.
Allowance cost	An allowance is equal to 1 metric ton of greenhouse gases. The cost for each allowance is determined through Ecology-facilitated quarterly auctions.
Arrearage Management Plans (AMP)	A bill forgiveness program offered by utilities to help income-qualified customers erase past-due utility debt.
Authorized baseline costs	Prudently incurred expenses and capital investments that regulators allow a utility to recover from customers. These are determined through rate cases, power cost only cases, and in certain circumstances power cost adjustment mechanisms.
Authorized delivery revenues	The specific amount of money regulators allow a utility to collect from customers to cover the costs of

	building, maintaining, and operating the electric grid. This separates the fixed costs from the fuel costs (variable cost).
Balancing Accounts	Accounting mechanism used to track the difference between a utility's authorized revenue requirement (determined for a specific issue in a rate case) and the actual amounts collected from customers. The variance is deferred and then collected or refunded to customers depending on the direction of the variance after approval by the regulator. This occurs on an annual basis. However, customer rates do not change to reflect that actual spending until they are approved and integrated into base rates in the next rate case.
Base rates	The fundamental pricing structure that allows a utility to recover its reasonable costs and earn a return (profit) on investments. The rates are approved through the formal adjudicative process (rate case proceeding). Base rates are distinct from revenues collected through other regulatory mechanisms (See trackers, balancing accounts, and rider definitions).
Beneficial electrification	Targeted programs, initiatives, strategies, or investments that promote the transition to electricity from heating oil, propane, and natural gas.
Bill credit	A refund on the customer bill.
Bill Discount Rate (BDR)	A low-income program that provides a discount based on a customer's household size and income. There are typically tiers of discount percentages based on a determined range of incomes.
Bill surcharge	An additional charge (cost) on the customer bill. An expense that has been approved to enable a utility to recover specific one-time items (*e.g.,* excess storm restoration costs incurred in a given year). It is a fixed amount over a defined period.
Bright-line threshold	A clearly defined, measurable standard or numeric limit that leaves no room for subjective interpretation.
Capex bias	A natural incentive for monopolies to prefer capital investment over operating expenditures. This occurs because a return (profit) is only earned on capital

	investments. It can lead to a utility choosing to build new things when a less expensive operational fix is more efficient.
Carrying costs	Compensate a utility for the time value of money when there is a delay between when the utility spends money and when it recovers those costs in rates (interest). However, the ability to both defer those costs for later recovery and apply carrying costs are subject to commission approval.
Clean Energy Implementation Plans (CEIP)	A four-year roadmap detailing how utilities transition to renewable energy while ensuring equitable benefits for communities. The plans are mandated by the Clean Energy Transformation Act under RCW 19.405.060.
Clean Energy Transformation Act (CETA)	Law that commits Washington to an electricity supply free of greenhouse gas emissions by 2045. See RCW 19.405.
Climate Commitment Act (CCA)	A "cap and invest" program that reduces greenhouse gas emissions from Washington's largest emitting sources and industries. Works alongside other critical climate policies to help Washington achieve its commitment to reducing greenhouse gas emissions by 95% by 2050.
Commodity cost	The price of the raw, actual energy (such as natural gas) consumed by the customer. It reflects the cost paid by the utility to purchase the resource and is passed directly to the consumer without markup.
Community-based organizations (CBO)	A nonprofit or grassroots group that operates locally to serve the specific needs of its residents. These organizations address issues like healthcare, housing, education, workforce development, and obtaining financial assistance (such as energy bill assistance).
Consignment revenues	The funds generated when the state auctions off carbon emission allowances that were originally given to utility companies at no cost. These specific funds are legally required to be routed directly back to the utilities to offset costs for their customers.
Consumer advocates	Represent the interests of the public and ratepayers before state or federal utility commissions. They act as

	the public's legal counsel in cases involving utility companies. This function is fulfilled by the Attorney General's Office in Washington.
Cost control	Regulatory function to ensure that the rate of spending growth is no more than necessary to support a safe, reliable grid while meeting public policy objectives. Rather than forcing arbitrary expense cuts, it requires continuous regulatory evaluation to ensure utilities spend efficiently.
Cost of capital	It represents the combined cost of the debt and equity used to fund assets (capital investments) and ensures utilities can attract investors while keeping customer rates fair. This can also be referenced as rate of return or weighted average cost of capital.
Cost-effectiveness tests	Standardized analytical tools use to evaluate whether proposed energy investments (such as energy efficiency portfolios, demand response programs, or distributed energy resources) provide more value than they cost.
Customer Benefit Indicators (CBIs)	Evaluation metrics mandated by the Clean Energy Transformation Act to track, quantify, and equitably distribute the benefits of the clean energy transition, prioritizing Highly Impacted Communities and Vulnerable Populations).
Dead bands	A defined monetary range where no financial adjustments or regulatory penalties are triggered. It acts as a tolerance buffer.
Decarbonization	The process of reducing and eliminating carbon dioxide and other greenhouse gas emissions from the economy.
Decommissioning and Remediation (D&R) costs	The legal and financial obligations to safely retire, dismantle, and clean up an industrial asset.
Deferral	Accounting mechanism that allows utilities to postpone the recognition of certain costs or revenues until a future period.
Demand response (DR)	Programs that incentivize electricity consumers to temporarily reduce or shift their energy usage during periods of high grid stress or peak demand.

Demand-side management (DSM)	Utility strategies that encourage consumers to optimize their electricity consumption. Energy efficiency measures permanently reduce consumption and demand response shifts usage to a different time.
Depreciation	Systematic process of allocating the original cost of a utility's long-term physical assets (such as power plants) across their expected useful lives. It is primarily a cost-recovery process rather than a measure of an asset's physical decline.
Distributed energy resource (DER)	A diverse category of devices and technologies that interface with the electric system at the distribution system level. These are either directly connected to a distribution utility's wires or on an end-use customer's premises, behind the utility meter.
Earnings test	Used to determine if a utility is making excessive profits based on actual, adjusted earnings against its authorized rate of return.
Electrification	The process of powering by electricity from another power source.
Embedded in rates	Approved costs (operating expenses, capital investments, and the associated rate of return) as authorized by the regulatory commission.
Energy burden	The percentage of gross household income spent on energy bills, including electricity, heating, and cooling. A household is generally considered to have a high energy burden if it spends more than 6% of its income on utilities.
Energy Independence Act (EIA)	Law requiring electric utilities serving at least 25,000 retail customers to meet specific renewable energy and energy conservation targets.
Energy market	Platforms where energy commodities – such as electricity, natural gas, oil, and renewable resources – are bought and sold. They function in highly coordinated, regional-specific auctions designed to match supply with demand in real-time, balancing power grids while determining wholesale and retail prices.

Environmental Remediation	The process of removing pollution and contaminants from soil, groundwater, sediment, and surface water.
Equity adders	Increase on a utility's authorized return on equity to incentivize specific, highly desired operational or societal outcomes that the utility might now otherwise pursue.
FERC rate	Interest rate determined by the Federal Energy Regulatory Commission on a quarterly basis.
Fixed costs	Expenses required to build, maintain, and operate infrastructure. These costs do not change regardless of how much electricity or gas a customer consumes.
Forecasting (methodologies)	Statistical and econometric models that rely on historical data to capture trends, seasonality, and liner relationships. The utility can use one or more methodologies and then run different scenarios to determine future needs.
Full decoupling	Makes the utilities indifferent to changes in sales, regardless of the reason. This differs from partial decoupling for only a portion of the utility's revenue or limited decoupling in which only specific causes of variations are considered.
General rate case (GRC or MYRP)	Formal regulatory proceedings where an energy utility requests permission to adjust the rates charged to customers. Rate cases are a subset of the different types of adjudicative proceedings. A multiyear rate plan is also considered a general rate case.
Generally Accepted Accounting Principles (GAAP)	Standardized set of accounting rules, standards, and procedures used in the United States. It dictates how companies must prepare and present their financial statements to ensure accuracy, consistency, and transparency.
Grid enhancing technologies (GETs)	A suite of hardware and software solutions – primarily Dynamic Line Ratings, Advanced Power Flow Controls, and Topology Optimization – designed to extract maximum capacity and efficiency from existing electrical transmission lines.
Integrated Resource Planning (IRP)	A long-range roadmap used by utility companies to forecast future energy demands and determine the

	least reasonable cost mix of resources to meet energy needs. The plans typically forecast 20 years into the future.
Integrated System Planning (ISP)	A regulatory framework allowing large utility companies (PSE only) that provide both electric and natural gas to merge their formerly separate, siloed infrastructure plans into a single, comprehensive roadmap.
Interested parties	Individuals, groups, or entities with a significant stake in utility services, rates, or policies.
Intervening parties	Interested parties that formally join ongoing regulatory proceeding. Intervenors are granted legal standing to present evidence, cross-examine witnesses, and file legal briefs, ensuring their specific interests are represented before a commission.
Known and measurable	A fundamental ratemaking principle used by regulatory commissions. It requires that adjustments made to a utility's historical operating costs or revenues must be based on actual, verifiable changes that are known to occur and can be calculated with reasonable accuracy.
Low Income Energy Assistance Program (LIHEAP)	A federally funding program that helps eligible low-income households manage and pay their costs for home energy. The program is administered by the Washington Department of Commerce.
Market linkage	The integration and coordination of separate geographic or operational energy markets.
Materiality threshold	Financial or operational benchmark used by regulatory commission to determine whether a utility's request, cost variance, or proposed change has met a minimum point. This definition is specific to the discussion of cost trackers or deferrals and should not be applied more broadly. Some parties also use bright-line threshold interchangeably with materiality threshold.
Mitigation activities	Proactive strategies and investments implemented by electric providers to minimize the likelihood of their infrastructure igniting a wildfire and to reduce the impact should a fire occur.

Monopoly	An arrangement in which a single provider has the exclusive right to supply an essential service to a specific geographic region.
Named Communities	A legally or regulatory-defined geographic area or demographic group designated to receive targeted infrastructure investments, financial incentives, or equity benefits. These designations ensure that historical, socioeconomic, and environmental disparities are addressed in the power sector. Washington state under the Clean Energy Transformation Act classifies this designation through Highly Impacted Communities and Vulnerable Populations.
Named Communities Investment Fund (NCIF)	A competitive grant program that funds up to $5 million annually to projects, programs, and initiatives that directly benefit Avista's Washington electric customers who are part of Named Communities.
No-cost allowance allocations	Allowances are issued by Ecology at no cost to electric utilities, natural gas utilities, and emissions-intensive, trade exposed (EITE) entities as determined by law or Ecology rules.
Non-pipes solutions	Targeted strategies and investments used by energy utilities to defer or avoid the costly construction or upgrade of traditional natural gas pipelines.
Non-wires solutions	Targeted strategies and investments used by energy companies to defer or avoid costly upgrades to transmission and distribution systems instead of building new poles and wires.
Offramp	A regulatory safeguard that allowed for the suspension, early termination, or adjustment of the rate plan before its scheduled end date. It is triggered by pre-defined conditions, such as extreme over-earning by the utility or severe economic downturns.
Pass-through accounting	Accounting mechanisms where specific operational or commodity costs (like fuel or taxes) are passed directly from the energy provider to the consumer without a profit markup.

Peak seasons	Typically refers to high heating and cooling months during the year depending upon the geographical region.
Performance Incentive Mechanism (PIM)	Regulatory tool that ties a portion of a utility's earnings or revenue to its performance in achieving specific policy, operational, or customer-service goals. Incentives can be a reward or penalty based on performance.
Performance metric	A quantifiable, objective standard used by regulators to measure a utility's outcomes, such as grid reliability or customer service quality.
Performance-based regulation (PBR)	A regulatory framework that ties a utility's financial performance and profit to its actual achievement of a specific, measurable outcomes rather than just its capital investments and operating costs.
Petition	A formal, written request submitted to a regulatory commission asking the request the authority to do, or not do, something.
Pilot programs	A small-scale, temporary trial used to test new technologies, rate structures, or customer services in a real-world setting before a large-scale rollout. It helps companies evaluate feasibility, address unforeseen challenges, and measure customer response with minimal financial and operational risk.
Policy statement	A formal, non-binding public document that outlines the commission's future intentions, guiding principles, or preferred methodologies on specific regulatory issues. It provides clarity and transparency to utilities and interested parties without the strict, legally enforceable mandate of a rule.
Portfolio management	Strategic process of maintaining physical assets. It ensures that the infrastructure delivering utility services operates reliably and cost-effectively throughout its lifecycle.
Portfolio-level review	An annual review of capital investments included in rates during a multiyear rate plan to determine if the total capital spending was under- or overspent rather than by individual project. Each individual project

	continues to be evaluated for prudency and used and useful guidelines.
Procurement	Process of sourcing, contracting, and managing essential services – such as electricity and natural gas.
Productivity factor	An economic benchmark (often called the X-factor). It represents the percentage by which the utility must outpace inflation through better technology, streamline operations, and optimized infrastructure.
Provisional plant	Utility plant (assets) that are temporarily included in rates subject to refund if project costs are deemed imprudent or are not used and useful during the annual review process.
Prudency	Standard used to judge whether a utility's management decisions and expenditures were reasonable. Under this principle, a utility can only recover costs from ratepayers if those expenses were efficiently and appropriately incurred, based on what the utility know or reasonably should have known at the time (no hindsight).
Prudency reviews	The process is which prudency is determined. This can take place in many different types of filings including but not limited to general rate cases, annual reviews, and tariff filings.
Rate base	The value of the utility's property and assets upon which it is legally permitted to earn a fair rate of return.
Rate case moratorium	A temporary (typically unwritten) agreement that prevents a utility company from filing for changes to its base rates under multiyear rate plans. Also referred to as a "stay-out" provision.
Rate of return (ROR)	A regulator-authorized percentage of profit a utility is permitted to early on its capital investments.
Rate schedules	The official pricing document or tariff that a utility files with regulators. It outlines exactly how much a utility can charge for consumption and defines the rules, fees, and rate structures applied to customer bills.
Rate shock	An abrupt and unusually large increase in the price of utility services.

Regulatory lag	The time delay between when a utility incurs new costs or makes infrastructure investments and when the regulator approves the new, higher rates required to recover those expenses. This is typically an 18-month period.
Renewable Energy Credit (REC)	A tradeable digital certificate that represents the environmental benefits of generating 1 megawatt hour (MWh) of electricity from a renewable source, such as solar or wind.
Resource planning	*See* the definition of Integrated Resource Planning.
Return on Equity (ROE)	The percentage of profit a regulator authorized a utility to earn on the equity portion of its rate base, determining how much money shareholders can legally make from customer bills.
Revenue requirement	The total amount of money a utility is legally allowed to collect from its customers to cover its costs and provide a reasonable return to shareholders.
Riders	A billing mechanism for recovery of specific charges from – or refunds to – customers. Riders often show up on customer bills as separate line-item costs that contribute to the total bill. Riders may be used as the mechanism to recover expenses through cost trackers, surcharges, and balancing accounts.
Risk-responsive hedging	Actions taken and measured value from continually evaluating and responding to changing risk conditions.
Risk-sharing mechanism (RSM)	A framework to divide the financial risks between utility shareholders and customers.
Rulemaking	A formal, public process used by regulators to create, amend, or repeal industry guidelines and regulations.
Shared savings mechanism (SSM)	A financial incentive that allows a utility and its customers to divide the net economic benefits created by cost-saving efforts or investments.
Shareholders	Investors who own equity in regulated utilities. In exchange for supplying capital (funds) to build and maintain massive energy infrastructure, these owners are entitled to a portion of the company's profits.
Sharing bands	Risk-sharing thresholds that split the financial risk of fluctuating costs between shareholders and

	customers. These bands determine what percentage of costs a utility is permitted to pass on to customers versus what they must absorb.
Storage utilization	Refers to how underground reservoirs or tanks are filled and drawn down to balance energy supply and demand. Operators inject surplus gas during mild months and withdraw it to meet heating or peak cooling demands.
System Average Interruption Duration Index (SAIDI)	The standard industry metric used by electric utilities to measure the total amount of time the average customer experiences a power outage over a specific period, typically a year.
System Average Interruption Frequency Index (SAIFI)	The standard industry metric used by electric utilities to measure how often the average customer experiences a sustained power outage over a given period, typically a year.
Tacoma Liquified Natural Gas (LNG) facility	A liquified natural gas production and storage depot located in the Port of Tacoma. It is owned by Puget LNG and a portion of the plant is utilized for the benefit of PSEs' energy customers that fall under regulation by the Commission.
Targets (scorecards)	Represent a specific and measurable value for utility performance.
Tariff Schedule	*See* the definition of Rate Schedule
Throughput incentive	A regulatory dynamic that motivates energy utilities to sell as much electricity or natural gas as possible to maximize their profits.
Tracker	A ratemaking mechanism that allows utilities to adjust recovery of specific expense categories instead of waiting for the next general rate case. Trackers cover eligible expenses through a separate rider, to which a later true-up to rates is usually performed to recover exactly the entitled amount of allowed revenue from customers. Some trackers may allow recovery of more or less than the exact amount of expenditures to ensure revenue is collected to cover carrying costs or due to incentives.

Transportation arrangements	Define how physical gas is moved through the pipeline network from producers to end-users.
Traditional Regulation	Also known as cost-of service regulation. The process involves the utility filing a request to change customer rates, the Commission determining the revenue requirement (authorized revenues) based on historical costs with limited adjustments, and when the rates become insufficient the cycle repeats.
Transportation Electrification Plan (TEP)	A framework designed for electric utilities to detail how they plan, develop, and implement EV programs to serve their customers.
True-up mechanism	A regulatory adjustment that reconciles the difference between a utility's estimated costs or revenues and its actual ones.
Used and Useful	A regulatory principle stating that a utility can only include the costs of assets – and charge customers for them – if the property is actively providing physical service (used) and customers are receiving the benefits from that plant (useful).
Vegetation management	The strategic practice of controlling and removing trees, brush, and plants near infrastructure like power lines, pipelines, and railways.
Wholesale natural gas market	A centralized market where large volumes of natural gas are bought and sold in bulk between producers, marketers, and utility companies before it reaches residential or commercial end-users.
Wildfire Mitigation Plan (WMP)	A comprehensive, state-mandated document outlining how electric utilities construct, maintain, and operate their power grids to minimize the risk of electrical infrastructure sparking wildfires.
Wildland-urban interface (WUI)	The geographic area where human development, such as homes and infrastructure, meets or intermingles with undeveloped wildland vegetation.

Appendix Reference List

The appendices are provided separately due to formatting and providing the native format of the documents.

Appendix A
Completed Regulatory Assessment Matrix

Appendix B
2021 – 2025 Regulatory Assessment Data Set

Appendix C
Table of Recommendations

Appendix D
Historical Mechanism Information

Appendix E
List of Helpful Resources

Appendix F
Regulatory Assessment Template for interested party use